TransGlobe Energy Corporation

2003 Annual Report

CONTENTS

ANNUAL MEETING

TransGlobe Energy Corporation will hold its Annual and Special Meeting on Wednesday, May 26, 2004 at 3:00 p.m. The meeting will be held in the Viking Room at the Calgary Petroleum Club located at 319 - 5th Avenue S.W., Calgary, Alberta, Canada.

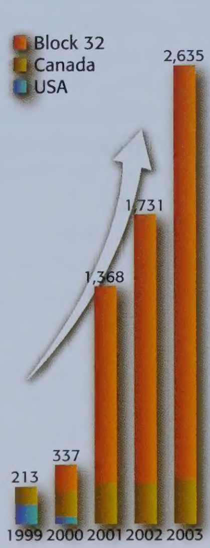
This annual report may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

HIGHLIGHTS

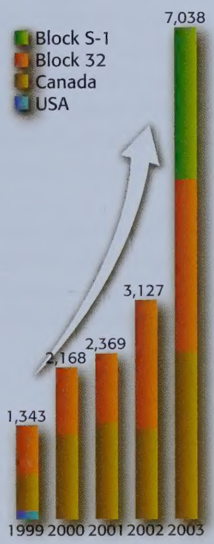
- *Production increased 54%*
- *Proven plus Probable reserves increased 125%*
- *Commerciality declared, Block S-1 Yemen*
- *Listing on the AMEX as TGA*
- *Payout of all historical costs achieved on Block 32 Yemen*
- *Record drilling program, 17 wells (8 oil, 7 gas, 1 potential gas & 1 D&A), 88% success*
- *December 31 working capital of $2,537,369 with no debt*

Cash Flow
(,000 US $)

Production
(Boed)



Proven and Probable Reserves
(MBoe)



Throughout the text of TransGlobe's annual report and consolidated financial statements, all dollar values are expressed in United States dollars unless otherwise stated.

MESSAGE TO THE SHAREHOLDERS

In 2003, TransGlobe accomplished several significant milestones, notably a 54% increase in production over 2002 levels, the early payout of historical costs on Block 32, commerciality on Block S-1, record drilling success in Canada, and a listing on the AMEX exchange. As significant as these achievements are, they seem like a warm up act for the line-up of events which are scheduled to unfold at the end of 2004 and beyond.

TransGlobe Energy is not a quarter by quarter story. Our international projects are chosen because they have "legs". Each one has multiple prospects, in multiple zones, which lowers exploration risk while maintaining major discovery potential. These projects may take three to five years to start cash flow, and another 5 to 10 years to fully exploit. For example, the Tasour project attained payout of all historical costs in 2003, six years from when the company entered into the project. When we built the facilities at Tasour, the field was thought to contain 6.9 million barrels. Since then, it has outperformed our expectations, producing more than 15 million barrels to date, and generating more than $350 million in gross sales. The Tasour project continues to offer the potential for increased production, as we still do not know how large the Tasour field is and we still have many exploration plays on the block waiting to be drilled. It is clear that this project will continue to produce for many years.

We take a conservative, long term approach to project exploitation. Once a discovery is made, we move quickly to field development and allow cash flow to fund further exploration. Further exploration becomes self supporting, funded by cash flow. We do not leverage the Company to fund exploration, reducing financial risk and dilution. This strategy allows the Company to maintain a strong balance sheet (as of December 31, 2003, the Company had working capital of $2.5 million with no debt). By focusing on only a few blocks of land we keep staff levels small and vigilant.

An event that I keenly await is the completion of the pipeline and start of full production from our second Yemen project at An Nagyah on Block S-1 in early 2005. If Tasour has been great for TransGlobe, S-1 is envisioned to eclipse it. Revenues will increase dramatically in early 2005 once the pipeline becomes fully operational, while some revenue will be generated by trucking oil in 2004. As with Tasour, this will mark only the beginning of Block S-1 development. There are numerous structures to be drilled, as well as further investigations into development/marketing of the Harmel shallow oil and An Naeem gas/condensate discoveries. Block S-1 is a long term project that will take several years to develop and exploit. If our assessment of the Block is correct, it ensures the growth of TransGlobe for years into the future.

As excited as I am about TransGlobe's future, the achievements of 2003 deserve some attention. An independent measure of our success was provided by qualifying TransGlobe common shares for listing on the AMEX exchange. Companies that qualify for an AMEX listing must meet high standards of financial strength and corporate governance. The AMEX listing provides increased visibility for the Company and increased liquidity for shareholders.

Ross G. Clarkson
President, CEO
and Director

Robert A. Halpin
Chairman of the Board
and Director

Canadian exploration was very successful, particularly the gas pools discovered at Nevis and Twining. These projects will provide the majority of the development drilling locations for 2004. Canadian exploration provides balance and diversification to our international ventures and has proven to be an excellent investment. An even larger drilling program of 14 wells in planned for 2004.

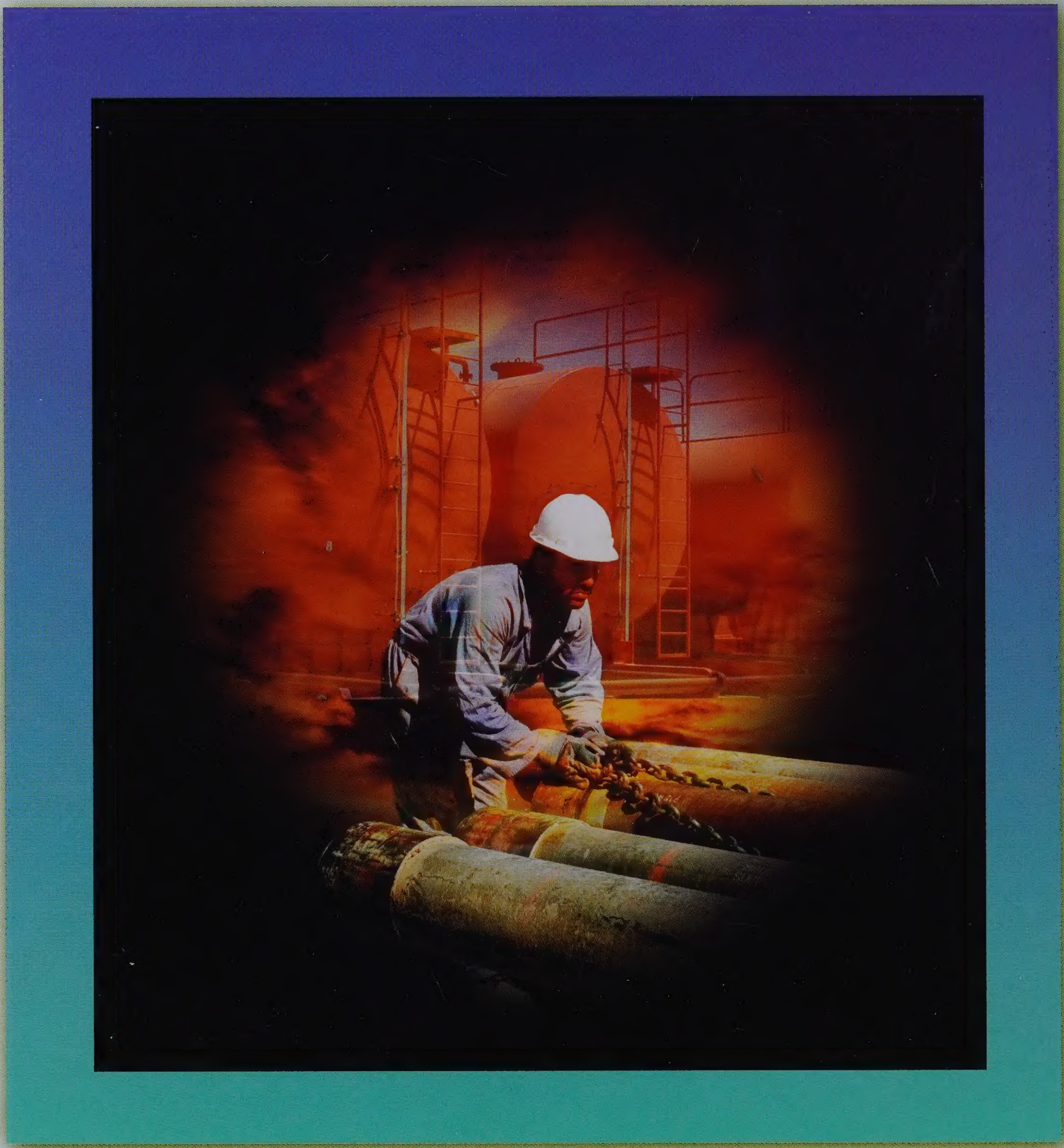
Oil and gas production for 2003 increased 54% over that achieved in 2002. The 2004 target is a 3,400 Boepd average rate (a 30% increase over 2003) to be followed by a further 50% increase in 2005 to 5,000 Boepd. If this target is achieved it will represent a production growth rate of 47% per year from 1999 to 2005.

In conclusion, the Company has all the elements needed to ensure future growth: new discoveries and reserve additions in all three operational areas; a strong balance sheet; and a very talented and experienced exploration and production team. We are well-positioned and prepared to build upon our success in 2004 and beyond.

Ross Clarkson

Ross G. Clarkson
President, CEO and Director

April 1, 2004



OPERATIONS REVIEW

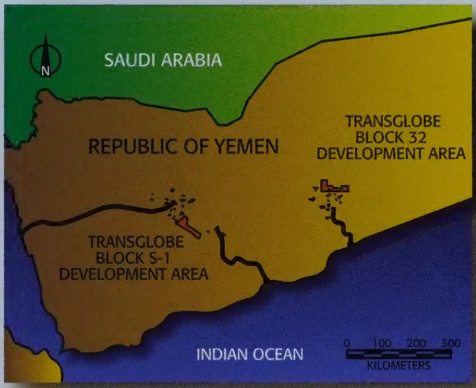
INTERNATIONAL ACTIVITY

BLOCK 32, REPUBLIC OF YEMEN

- Four oil wells and one D&A well drilled in 2003, 80% success
- Western extension to Tasour field discovered
- Tasour averaged 17,175 Bopd (2,372 Bopd to TransGlobe) in 2003
- Proven and Probable reserves increased 32%, replacing 169% of annual production
- Payout of all historical costs achieved Q2 2003

Background

TransGlobe entered into its first international project in January 1997 through a farmout agreement and joint venture on Block 32. The Company has since participated in acquisition of seismic data, drilling of seventeen wells and construction of production facilities, resulting in commencement of Tasour field production on November 3, 2000. The joint venture consists of TG Holdings Yemen Inc. (a wholly-owned subsidiary of TransGlobe Energy Corporation) with a 13.81087% working interest and partners Ansan Wikfs Hadramaut Ltd. and DNO ASA holding the balance ("the Block 32 Joint Venture Group"). DNO ASA (an independent Norwegian oil company) is the operator of the Block. The Yemen Oil Company ("YOC" - a Yemen government oil company) has a 5% interest in the Block 32 Joint Venture Group's production sharing oil.



The Block 32 development area covers 591 square kilometers (146,070 acres). The development area encompasses all of the Tasour structure and several additional prospects. The approved development/production period extends until the year 2020, with an optional five-year extension to 2025.

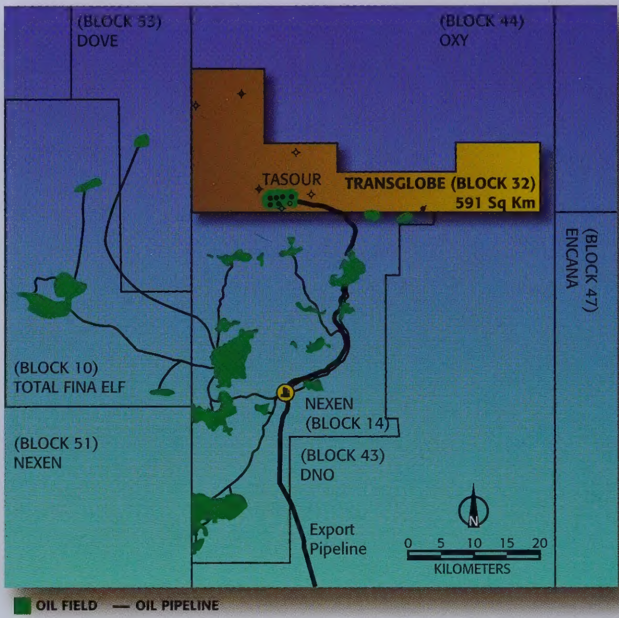
2003 Activities and Results

Exploration

The 2003 Block 32 Joint Venture work program consisted of the drilling of three development/appraisal wells and two exploration wells. The five wells resulted in an exploratory dry hole at Haibish and four producing oil wells (Tasour #8, #9, #10 and #11) summarized in the table below:

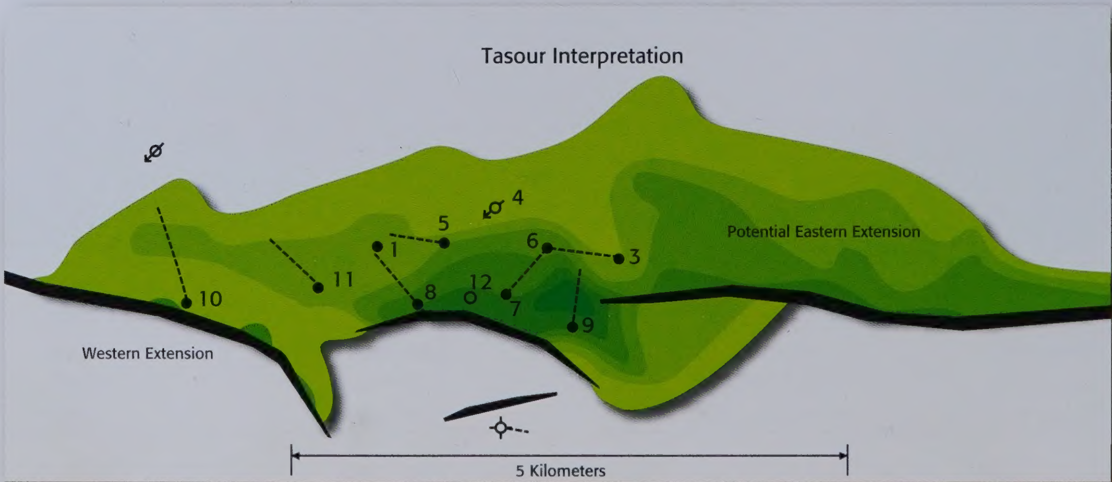
2003 Drilling Results

Well	Date Completed	Initial Production Rate	Producing Formation
Tasour #8	January 2003	9,000 Bopd	Qishn
Haibish #1	February 2003	-	D&A
Tasour #9	April 2003	1,500 Bopd	Qishn
Tasour #10	July 2003	1,200 Bopd	Qishn
Tasour #11	November 2003	6,000 Bopd	Qishn



The Tasour #8 and #9 development wells confirmed the southern field extension discovered by Tasour #7 in 2002. The Tasour #10 well was a successful test of the western field extension. This discovery extended the mapped Tasour field length from 3.3 kilometers to approximately 6.8 kilometers. Tasour #11 confirmed the western field extension creating a series of new development locations.

The western field extension combined with continued field performance increased proven plus probable reserves 32% and replaced 169% of 2003 production. Seismic mapping indicates the Tasour field could extend both to the west and to the east of the current wells. In late 2003, the Block 32 Joint Venture Group approved a 100 square kilometer 3-D seismic acquisition survey over the greater Tasour area to refine future drilling locations. It is anticipated that the 3-D seismic will be completed and interpreted by June 2004. Further development/appraisal drilling of three to four wells in the western and potential eastern extension is planned for 2004. One infill well is planned for the central Tasour pool in May 2004 (Tasour #12).



Production

The Tasour field averaged 17,175 Bopd (2,372 Bopd to TransGlobe) during 2003 compared to 11,187 Bopd (1,545 Bopd to TransGlobe) during 2002, representing a 54% increase. Production increases are attributed to the new wells (Tasour #8, #9, #10 and #11) drilled to develop the southern and western extensions of the Tasour field. The Tasour field has produced at peak rates in excess of 23,000 Bopd (3,177 Bopd to TransGlobe) during November 2003 with the addition of Tasour #11. It is expected that production from the Tasour field will average approximately 16,000 Bopd (2,210 Bopd to TransGlobe) for the year 2004, which is consistent with the predicted natural declines for the field.

The table below lists the Tasour production during 2003 and shows the effect on net barrels when payout of historical costs was achieved during the second quarter.

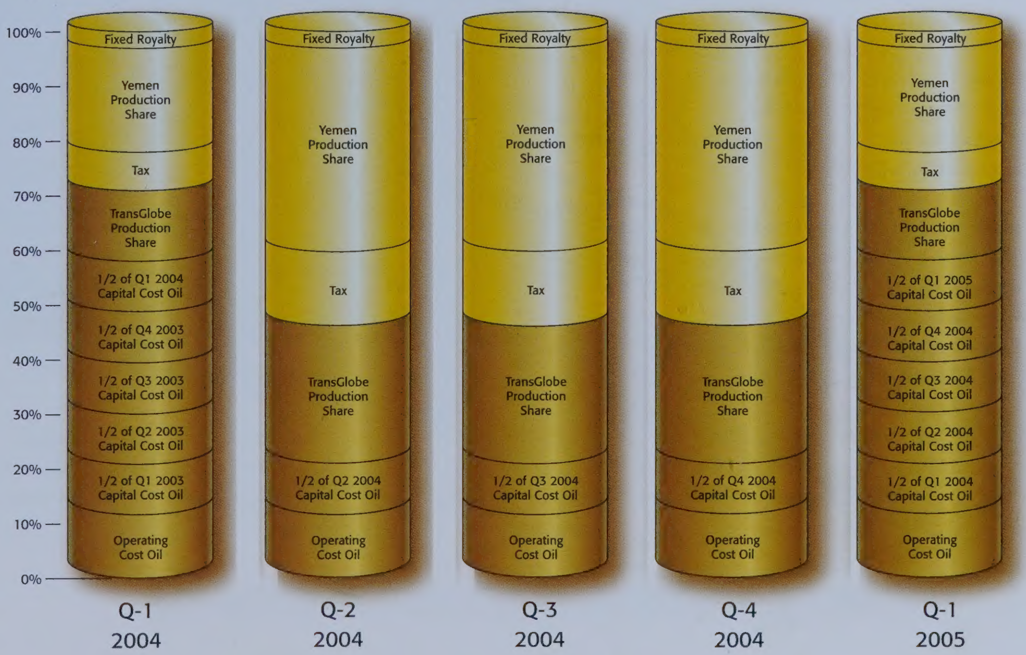
2003 Tasour Production by Quarter (Bopd)

	Q-1	Q-2	Q-3	Q-4
Gross Field Production Rate	16,700	16,510	17,783	17,689
TransGlobe Working Interest	2,307	2,280	2,456	2,443
TransGlobe Net (after royalties)	1,800*	1,684*	1,400	1,330
TransGlobe Net (after royalties and tax)	1,640*	1,490*	1,040	1,031

* *The Q1 and Q2 numbers presented are prior to the final cost oil allocation of $1,245,000 paid to the Block 32 Joint Venture parties, which was booked as a royalty expense.*

The Block 32 Production Sharing agreement allows for the recovery of operating costs and capital costs from oil production. Operating costs are recovered in the quarter expended. The capital costs are amortized over two years with 50% recovered in the quarter expended and the remaining 50% recovered in the first quarter of the following calendar year. The following diagram depicts the approximate production splits for 2004 and the first quarter of 2005. The Company will receive a larger share of production in the first quarter of each year as 50% of the previous year's capital costs are recovered. The amount of cost oil required to recover capital and operating costs will vary depending upon the prevailing oil prices.

Illustration of estimated future production splits



2004 Outlook

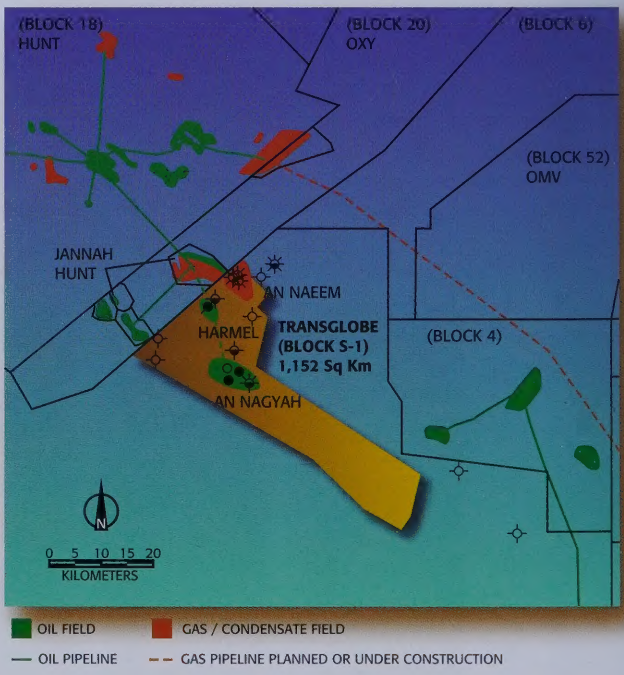
The outlook for Block 32 remains positive as the Tasour field continues to outperform our expectations. The western extension will provide several new development locations for 2004 and should maintain production levels in the 16,000 Bopd range. Block 32 will continue to produce a significant portion of TransGlobe's future revenues. The eastern extension has the capability to maintain production levels beyond 2005 if it proves out with future drilling. There are also a number of exploration prospects identified for future drilling.

BLOCK S-1, REPUBLIC OF YEMEN

- Two oil wells and one gas/condensate well drilled in 2003, 100% success
- Commerciality declared on October 14, 2003
- 1,152 square kilometer (284,700 acre) Development Area secured for 20 years
- Early production by trucking oil commenced March 2004
- Facility and pipeline development completion planned for first half 2005

Background

TransGlobe entered into its second international exploration venture in 1997 by signing a Production Sharing Agreement ("PSA") for the Damis S-1 Block ("Block S-1") with the Ministry of Oil and Minerals ("MOM"). TG Holdings Yemen Inc. (a wholly owned subsidiary of TransGlobe Energy Corporation) entered into a joint venture arrangement for Block S-1 with a subsidiary of Vintage Petroleum Inc., a U.S. independent exploration and production company ("Block S-1 Joint Venture Group"). During 2000 Vintage earned a 75% working interest in Block S-1 by funding 100% of the work commitments for the first exploration period of the Block S-1 PSA and by spending a minimum of $20 million. TransGlobe has retained a 25% working interest in Block S-1. Vintage is the operator of Block S-1. The YOC has a 17.5% interest in the Block S-1 Joint Venture Group's share of production sharing oil.



The first exploration period ended on March 28, 2002 and the Block S-1 Joint Venture Group elected to proceed with a second exploration period of 2 1/2 years. The second exploration period commitments were satisfied by the drilling of An Naeem #2 (2000), Osaylan #1 (2002), An Nagyah #2 (2002) and a 3-D seismic survey (2001).

Block S-1 originally encompassed an area of 4,484 square kilometers (approximately 1.1 million acres). Upon declaring commerciality in October 2003, a final relinquishment reduced the Block to a Development Area of 1,152 square kilometers (284,700 acres). The Development Area is now valid until October 2023 (20 years) with an additional five year extension available.

2003 Activities and Results

Exploration

The drilling program commenced in September 2002 was completed in May 2003, resulting in three oil wells, one gas/condensate well and one dry hole. The wells drilled during 2003 were An Naeem #3 (gas/condensate), An Nagyah #3 (oil) and An Nagyah #4 (oil).

2003 Drilling Results

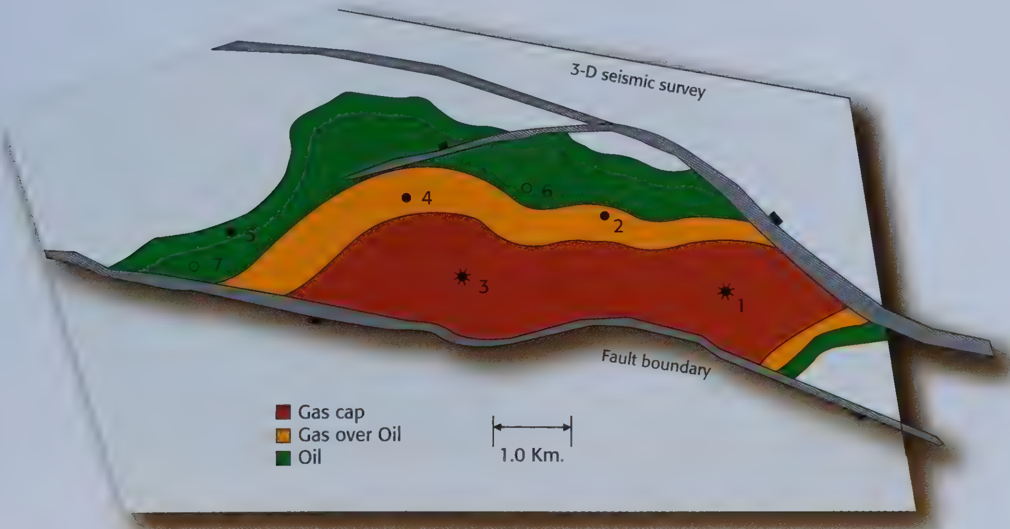
Well	Date Completed	Results	Formation
An Naeem #3	January 2003	Gas/condensate	Alif
An Nagyah #3	March 2003	Gas, not tested	Lam 'A'
		Oil: 240 Bopd	Lam 'B'
An Nagyah #4	April 2003	Oil: 1,320 Bopd	Lam 'A'

The first well, An Naeem #3, was drilled to a total depth of 1,623 meters to evaluate a potential oil rim on the An Naeem structure. The An Naeem #3 well tested gas and condensate from the Alif zone and did not encounter the anticipated oil rim.

The next well, An Nagyah #3, commenced drilling in February 2003 to appraise the light oil discovery made at An Nagyah #2 (1,100 Bopd announced December 10, 2002). The well was drilled to a total depth of 1,292 meters and encountered the Upper Lam sandstones in a structurally higher position than the An Nagyah #2 well. Although the Upper Lam sandstones had a thicker gross reservoir section and better indicated porosity and permeability than found at An Nagyah #2, the Upper Lam was not flow tested as it was gas bearing. The well did test 240 Bopd of light, 42 degree API oil from a new pool in the Lower Lam. The core and test data indicate the Lower Lam reservoir has less porosity and permeability than the Upper Lam reservoir and therefore may require stimulation to enhance production. The discovery of a new productive horizon in the Lower Lam should augment development economics.

The next well in the program, An Nagyah #4, was drilled to a total depth of 1,547 meters and tested 1,320 barrels of light oil (45 degrees API) from the Upper Lam reservoir. The An Nagyah #4 well encountered a much thicker gross sand package and defined a 60 meter (197 feet) total oil column in the Nagyah pool. A longer term test of the An Nagyah #4 well was carried out during June/July confirming the original flow rates and pressures. The successful appraisal well at An Nagyah #4 convinced the Block S-1 partners to declare commerciality and proceed with development of the field.

An Nagyah Field Interpretation of Upper Lam Reservoir



Development Plan

On October 14, 2003 the Company announced the Declaration of Commerciality and on October 15, 2003 the Ministry of Oil and Minerals approved the Block S-1 Development Plan and Development Area of approximately 1,150 square kilometers (285,000 acres). The large Development Area encompasses the An Naeem, Harmel and An Nagyah discoveries as well as numerous additional prospects for future exploration drilling. The Development/Production period will extend until 2023 with an optional five year extension also possible.

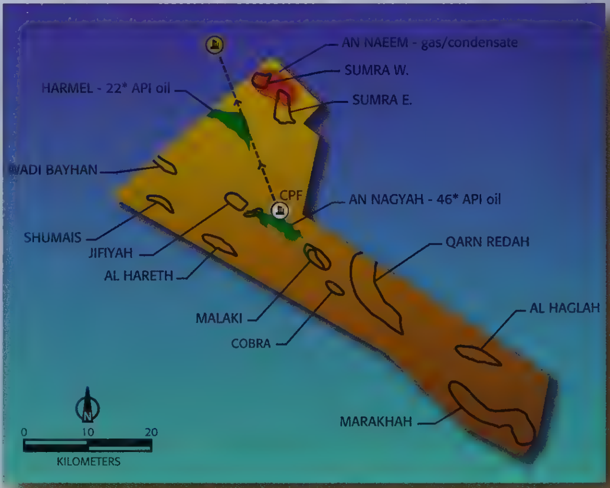
The initial field development is focused on the An Nagyah light oil pool which was discovered and appraised during the 2002/2003 drilling program. The plan provides for early production commencing in the first quarter of 2004 by trucking up to 2,500 Bopd (625 Bopd to TransGlobe) from An Nagyah wells. The equipment required to begin trucking oil 28 kilometers (18 miles) from An Nagyah #4 to the Hunt operated Halewah facility was installed during Q1 2004 and trucking commenced March 30, 2004.

The construction of a central production facility ("CPF") at An Nagyah and a 28 kilometer (18 mile) pipeline to the Jannah Hunt Halewah export pipeline is planned during 2004, with an anticipated completion by early 2005. The pipeline design was increased from an 8 inch to a 10 inch pipeline to allow future discoveries to be placed on stream quickly (ultimate capacity of 80,000 Bopd). The CPF is designed for an initial capacity of 10,000 Bopd (2,500 Bopd to TransGlobe), with expansion capabilities. The initial front end engineering and design ("FEED") study is complete. Bid requests for detailed engineering and for long lead time major equipment have been issued.

It is expected that the An Nagyah field development will consist of 13 wells to delineate and produce the field. The first development/appraisal well (An Nagyah #5) commenced drilling on the western area of the An Nagyah field on March 8, 2004. An Nagyah #5 was drilled to a total depth of 1,300 meters and completed as an Upper Lam 'A' oil producer. The well flow tested at a rate of 1,150 Bopd of 45 degree API oil. The well is being equipped for early production via trucking which is expected to commence in April. The drilling rig has moved to An Nagyah #6 (development well) and commenced drilling on April 7, 2004. Following An Nagyah #6, it is expected that the rig will be moved to An Nagyah #7 and then to Harmel #2 to appraise the shallow depth, medium gravity oil discovered in Harmel #1. Additional development wells in the An Nagyah pool are expected to be drilled in the third and fourth quarters of 2004 and into 2005.

2004 Outlook

The primary focus for 2004 and 2005 will be the development of the An Nagyah field. The facilities and pipeline are planned to be operational in the first half of 2005. Future exploration drilling will focus on the structures adjacent to the An Nagyah CPF. The prospect map below shows the numerous structures identified on Block S-1. It will take several years to fully evaluate the true potential of the large development area.



CPF - Central Production Facility ---- Planned pipeline

Block S-1 prospects

CANADA

- Nine wells drilled, six gas, two oil and one potential gas well, 88% success
- Production averaged 263 Boepd in 2003, up 41% over 2002
- Proven plus Probable reserves increased 88% replacing 1,292% of production
- Closed Cdn$3 million financing for 2004 exploration program

Background

TransGlobe acquired its Canadian operations in April 1999. The majority of the Canadian operations are operated by TransGlobe and are focused almost entirely in the southern/central part of the province of Alberta. Until 2003, investment in Canadian operations was limited to development and exploitation of producing areas with minimal investment in land or exploration opportunities. In 2003, Canadian operations were successfully expanded, providing increased cash flow and asset value. Canadian operations will continue to be expanded to capitalize on the North American gas market.

2003 Activities and Results

The Company drilled nine wells during the second half of 2003 resulting in six gas wells, two oil wells and one potential gas well. The Canadian proven plus probable reserves were increased 88%, replacing 1,292% of 2003 production. The Company had anticipated an exit rate of 1,000 Boepd could have been achieved if all the new wells were placed on production by year end. Unfortunately, several projects were postponed due to delays in obtaining approvals from surface landowners and/or government. Production averaged 436 Boepd in December, 2003 and is expected to average 450 to 550 Boepd during the first half of 2004. An additional 470 Boepd of production at Nevis, Twining and Morningside is awaiting installation of pipelines and facilities. It is anticipated that these projects could be on production during the first half of 2004.

2004 Outlook

TransGlobe plans to drill fourteen wells during 2004. The majority of the wells will be drilled after spring breakup (April/May), during the summer months when it is expected that drilling equipment and services will be available at better prices. Traditionally, the winter months (December through March) are the busiest and most expensive time to conduct drilling operations. The prospects are natural gas focused and are located in Central Alberta, which generally affords year round access. In addition to development/appraisal drilling planned at Nevis and Twining, several higher risk/higher reward exploration wells are planned.

PRODUCTION

The following table is a summary of average working interest daily production, **before royalty**, by country for the years ended 2003 and 2002:

	2003			2002		
	Oil & Liquids Bopd	**Gas Mcfpd**	**Total Boepd**	Oil & Liquids Bopd	Gas Mcfpd	Total Boepd
Yemen	2,372	-	2,372	1,545	-	1,545
Canada	63	1,200	263	37	892	186
Total	2,435	1,200	2,635	1,582	892	1,731

RESERVES AND ESTIMATED FUTURE NET REVENUES

Outtrim Szabo Associates Ltd. ("OSAL") of Calgary, Alberta, independent petroleum engineering consultants, evaluated the Company's Canadian reserves at December 31, 2003 and 2002. In Canada, proven reserves increased 92% to 1,483 MBoe at year end 2003 from 772 MBoe at year end 2002. The increase is attributed new wells drilled during 2003.

Fekete Associates Inc. ("Fekete") of Calgary, Alberta, independent petroleum engineering consultants, evaluated the Company's reserves in the Republic of Yemen at December 31, 2003 and 2002. TransGlobe's proven reserves in Yemen increased 44% to 2,263 MBbls at year end 2003 from 1,575 MBbls at year end 2002. The majority of the proven increases in Yemen were attributed to drilling the western extension of the Tasour field on Block 32. Also, with the declaration of commerciality on Block S-1 in 2003, proven reserves of 228 MBbls associated with trucking early production from the An Nagyah field were included in the 2003 year end numbers. Reserves have only been assigned to the Tasour field in Block 32 and a portion of An Nagyah field in Block S-1. Reserves numbers presented are at year end 2003, and therefore do not include results from the An Nagyah #5 well which was drilled subsequent to year end.

The Company's Reserves Committee (formed during 2003), comprised of independent and qualified directors, has reviewed and recommended acceptance of the 2003 year end reserve evaluations prepared by OSAL and Fekete.

The 2003 year end reserves were prepared by the Company's independent reserve evaluators in accordance with the new Canadian National Instrument (NI) 51-101 policy. The 2002 year end reserves were prepared in accordance with National Policy 2-B, therefore a direct comparison year over year is not completely valid. The Company's 2003 proven reserves were not materially affected by the more stringent proven definitions in (NI) 51-101. The most significant change is to Probable reserves. The new (NI) 51-101 policy has adopted a P-50 level of certainty ("at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated proved plus probable reserves") for Proven plus Probable reserves. Under the previous National Policy 2-B, Probable reserves were un-risked.

It is expected that the Company's International reserves reported under policy (NI) 51-101, will generally be more conservative than those booked by a joint venture partner reporting under SEC standards, especially newer reserves with little or no production history.

Reserves

Company By Category	2003 Light & Medium Crude Oil Gross* (MBbls)	Net** (MBbls)	Natural Gas Gross* (MMcf)	Net** (MMcf)	Natural Gas Liquids Gross* (MBbls)	Net** (MBbls)	Total 2003 Boe's Gross* (MBoe)	Net** (MBoe)	2002 Total 2002 Boe's Gross* (MBoe)	Net** (MBoe)
Proven										
Producing	2,083	1,358	3,155	2,494	93	69	2,703	1,843	1,903	1,268
Non-Producing	263	191	2,475	1,936	73	50	748	563	444	344
Undeveloped	-	-	1,422	1,068	58	39	295	217	-	-
Total Proven	2,346	1,549	7,052	5,498	224	158	3,746	2,623	2,347	1,612
Proven + Probable***	4,701	3,137	11,969	9,391	341	242	7,037	4,945	3,127	2,180

* *Gross reserves are the Company's working interest share before the deduction of royalties.*

** *Net reserves are the Company's working interest share after the deduction of royalties. Net reserves in Yemen include our share of future cost recovery and production sharing oil after the Government's royalty interest but before reserves relating to income taxes payable. Under this method, a portion of the reported reserves will increase as oil prices decrease (and vice versa) as the barrels necessary to achieve cost recovery change with prevailing oil prices.*

*** *Proven plus Probable reserves in 2003 were risked at 50%, whereas 2002 Probable reserves are unrisked.*

Reserves

Company By Area	2003 Oil & Liquids Gross (MBbls)	Net (MBbls)	Gas Gross (MMcf)	Net (MMcf)	Total Boe's Gross (MBoe)	Net (MBoe)	2002 Total Boe's Gross (MBoe)	Net (MBoe)
Proven								
Canada	307	231	7,052	5,498	1,483	1,147	772	600
Yemen Block 32	2,035	1,316	-	-	2,035	1,316	1,575	1,012
Yemen Block S-1	228	160	-	-	228	160	-	-
Total Proven	2,570	1,707	7,052	5,498	3,746	2,623	2,347	1,612
Proven + Probable								
Canada	437	328	11,969	9,391	2,432	1,893	1,291	1,008
Yemen Block 32	2,429	1,560	-	-	2,429	1,560	1,836	1,172
Yemen Block S-1	2,176	1,492	-	-	2,176	1,492	-	-
Total Proven + Probable	5,042	3,380	11,969	9,391	7,037	4,945	3,127	2,180

Proven Reserves Reconciliation

	Canada				Yemen Block 32		Yemen Block S-1	
	Oil & Liquids		Natural Gas		Oil		Oil	
	Gross (MBbls)	Net (MBbls)	Gross (MMcf)	Net (MMcf)	Gross (MBbls)	Net (MBbls)	Gross (MBbls)	Net (MBbls)
Reserves at Dec. 31, 2002	183	137	3,536	2,780	1,575	1,012	-	-
Extensions/Discoveries	161	120	5,201	4,079	1,326	876	228	160
Revisions	(14)	(7)	(1,247)	(988)	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-
Divestitures	-	-	-	-	-	-	-	-
Production	(23)	(19)	(438)	(373)	(866)	(572)	-	-
Reserves at Dec. 31, 2003	307	231	7,052	5,498	2,035	1,316	228	160

Proven Plus Probable Reserves Reconciliation

	Canada				Yemen Block 32		Yemen Block S-1	
	Oil & Liquids		Natural Gas		Oil		Oil	
	Gross (MBbls)	Net (MBbls)	Gross (MMcf)	Net (MMcf)	Gross (MBbls)	Net (MBbls)	Gross (MBbls)	Net (MBbls)
Reserves at Dec. 31, 2002	217	161	6,450	5,078	1,836	1,172	-	-
Extensions/Discoveries	258	192	8,051	6,304	1,459	960	2,176	1,492
Revisions	(15)	(6)	(1,622)	(1,215)	-	-	-	-
Acquisitions	-	-	-	-	-	-	-	-
Divestitures	-	-	(472)	(403)	-	-	-	-
Production	(23)	(19)	(438)	(373)	(866)	(572)	-	-
Reserves at Dec. 31, 2003	437	328	11,969	9,391	2,429	1,560	2,176	1,492

Estimated Future Net Revenues

The estimated future net revenues presented do not represent fair market value.

The estimated future net revenues presented below are calculated using the average price received during the final month of the respective reporting periods. The prices were held constant for the life of the reserves.

Present Value of Future Net Revenues, Before Income Tax
Constant Pricing

	Dec. 31, 2003 Discounted at				Dec. 31, 2002 Discounted at			
	Undis-counted ($MM)	**10% ($MM)**	15% ($MM)	**20% ($MM)**	Undis-counted ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proven								
Yemen *	18.0	15.7	14.8	14.0	13.3	11.9	11.3	10.8
Canada **	29.9	21.4	18.7	16.7	12.2	8.8	7.7	6.9
Total Proven	47.9	37.1	33.5	30.7	25.5	20.7	19.0	17.7
Proven + Probable								
Yemen *	36.4	29.0	26.1	23.7	15.4	13.6	12.8	12.2
Canada **	48.9	31.2	26.7	23.3	20.1	12.8	10.9	9.5
Total Proven + Probable	85.3	60.2	52.8	47.0	35.5	26.4	23.7	21.7

* *Yemen future net revenues presented are after Yemen income tax.*

** *Canadian values converted at the December 31, 2003 and December 31, 2002 exchange rates of 1.2965 and 1.5776 $US/$Cdn respectively.*

The estimated future net revenues presented below are calculated using pricing forecasts of the respective independent engineering consulting firms.

Present Value of Future Net Revenues, Before Income Tax
Independent Evaluators' Price Forecast

	Dec. 31, 2003 Discounted at				Dec. 31, 2002 Discounted at			
	Undis-counted ($MM)	**10% ($MM)**	15% ($MM)	**20% ($MM)**	Undis-counted ($MM)	10% ($MM)	15% ($MM)	20% ($MM)
Proven								
Yemen *	12.2	10.8	10.2	9.7	9.1	8.2	7.8	7.5
Canada **	19.7	14.2	12.5	11.2	7.9	5.8	5.2	4.7
Total Proven	31.9	25.0	22.7	20.9	17.0	14.0	13.0	12.2
Proven + Probable								
Yemen *	22.0	17.2	15.3	13.7	10.4	9.3	8.8	8.4
Canada **	32.3	20.4	17.5	15.3	12.6	8.3	7.1	6.3
Total Proven + Probable	54.3	37.6	32.8	29.0	23.0	17.6	15.9	14.7

* *Yemen future net revenues presented are after Yemen income tax.*

** *Canadian values converted at the December 31, 2003 and December 31, 2002 exchange rates of 1.2965 and 1.5776 $US/$Cdn respectively.*

The following table summarizes the **constant pricing** used to estimate future net revenues.

	December 2003		December 2002	
	Oil US$/Bbl	**Natural Gas US$/Mcf**	Oil US$/Bbl	Natural Gas US$/Mcf
Yemen *	30.05	-	30.28	-
Canada **	27.78	5.45	25.23	4.24

* *Yemen prices are based on prices received for Tasour production from Block 32.*

** *Canadian prices are based on prices received for Canadian production converted at the December 31, 2003 and December 31, 2002 exchange rates of 1.2965 and 1.5776 $US/$Cdn respectively.*

The following table summarizes the **independent evaluator price forecast** used to estimate future net revenues.

	Yemen (Fekete Pricing)		North America (Outtrim Pricing)			
	WTI Oil Ref. US$/Bbl		WTI Oil Ref. US$/Bbl		Gas-AECO Spot US$/Mcf	
Year	**2003**	2002	**2003**	2002	**2003***	2002*
2003	**N/A**	24.75	**N/A**	26.00	**N/A**	3.58
2004	**26.50**	22.50	**26.39**	23.35	**4.28**	3.21
2005	**23.50**	21.75	**24.21**	21.63	**3.69**	2.93
2006	**23.50**	22.00	**23.53**	21.96	**3.57**	2.95
2007	**24.00**	22.45	**23.88**	22.29	**3.61**	2.97
2008	**24.48**	22.90	**24.24**	22.62	**3.59**	3.01
Escalated	**2%/yr**	2%/yr	**1.5%/yr**	1.5%/yr	**1.2% to 14 Then 1.5 %**	1.2% to 13 Then 1.5%

* *Canadian values converted at the December 31, 2003 and December 31, 2002 exchange rates of 1.2965 and 1.5776 $US/$Cdn respectively.*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TransGlobe Energy
AMERICAN
STOCK EXCHANGE
Equities Options ETFs

MANAGEMENT'S DISCUSSION AND ANALYSIS

April 1, 2004

The following discussion and analysis is management's opinion of TransGlobe's historical financial and operating results and should be read in conjunction with the message to the shareholders, the operations review, the audited consolidated financial statements of the Company for the years ended December 31, 2003 and 2002, together with the notes related thereto. The consolidated financial statements have been prepared in accordance with accounting principles generally accepted in Canada. The effect of significant differences between Canadian and United States accounting principles is disclosed in Note 14 of the consolidated financial statements. Additional information relating to the Company, including the Company's Annual Information Form, is on SEDAR at www.sedar.com.

All dollar values are expressed in U.S. dollars, unless otherwise stated. The calculations of barrels of oil equivalent ("Boe") are based on a conversion rate of six thousand cubic feet of natural gas to one barrel of crude oil.

This Management's Discussion and Analysis (MD&A) may include certain statements that may be deemed to be "forward-looking statements" within the meaning of the U.S. Private Securities Litigation Reform Act of 1995. All statements in this annual report, other than statements of historical facts, that address future production, reserve potential, exploration drilling, exploitation activities and events or developments that the Company expects, are forward-looking statements. Although TransGlobe believes the expectations expressed in such forward-looking statements are based on reasonable assumptions, such statements are not guarantees of future performance and actual results or developments may differ materially from those in the forward-looking statements. Factors that could cause actual results to differ materially from those in forward-looking statements include, but are not limited to, oil and gas prices, exploitation and exploration successes, continued availability of capital and financing, and general economic, market or business conditions.

SELECTED FINANCIAL INFORMATION

	2003 $	% Change	2002 $	% Change	2001 $
Oil and gas sales, net of royalties	**17,161,710**	29	13,254,105	55	8,554,085
Cash flow from operations	**9,347,001**	(4)	9,709,852	66	5,840,455
Cash flow from operations per share					
- Basic	**0.18**		0.19		0.12
- Diluted	**0.17**		0.19		0.11
Net income	**5,905,228**	9	5,426,389	77	3,062,237
Net income per share					
- Basic	**0.11**		0.11		0.06
- Diluted	**0.11**		0.10		0.06
Total assets	**35,214,816**	44	24,386,147	29	18,847,489

Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. We consider this a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Cash flow from operations may not be comparable to similar measures used by other companies.

RESULTS OF OPERATIONS

Net income for 2003 was $5,905,228 ($0.11 per share basic and $0.11 per share diluted) compared to a net income of $5,426,389 ($0.11 per share basic and $0.10 per share diluted) in 2002. Cash flow from operations for 2003 was $9,347,001 ($0.18 per share basic and $0.17 per share diluted) compared to $9,709,852 ($0.19 per share, basic and diluted) in 2002.

Although net income and cash flow from operations were only increased (decreased) by 9% and (4)% respectively, there are significant changes that impacted these items in 2003. The following is a brief summary of the primary changes that occurred during 2003 that will be discussed in more detail throughout this MD&A:

- Higher production volumes
- Higher commodity prices
- Payout of all historical costs on Block 32, Yemen
- Cost oil reallocation on Block 32, Yemen increased royalty costs between 2003 and 2002 by approximately $2,594,000.
- Recognition of future income tax asset in Canada.

OPERATING RESULTS

Daily Production, before royalties

			2003	2002	% Change
Yemen	- Oil	Bopd	2,372	1,545	54
Canada	- Oil and liquids	Bopd	63	37	70
	- Gas	Mcfpd	1,200	892	35
Barrels of oil equivalent (6 : 1)		Boepd	2,635	1,731	52

The Company has set a target of 3,400 Boepd for 2004 representing a 30% increase over 2003.

Consolidated Net Operating Results

	Consolidated			
	2003		2002	
	$	$/Boe	$	$/Boe
Oil and gas sales	27,335,841	28.43	15,386,359	24.34
Royalties	10,174,131	10.58	2,132,254	3.37
Operating expenses	3,706,096	3.85	1,843,273	2.92
Net operating income*	13,455,614	14.00	11,410,832	18.05

* *Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in the Republic of Yemen (2003 - $2,755,067 $2.87/Boe; 2002 - $986,862, $1.56/Boe).*

Segmented Net Operating Results

In 2003 the Company operated in two geographic areas, segmented as the Republic of Yemen and Canada. MD&A will follow under each of these segments.

Republic of Yemen

	2003		2002	
	$	$/Boe	$	$/Boe
Oil sales	24,356,094	28.13	14,206,217	25.18
Royalties	9,731,206	11.24	1,967,506	3.49
Operating expenses	3,011,620	3.48	1,394,379	2.47
Net operating income*	11,613,268	13.41	10,844,332	19.22

* *Net operating income amounts do not reflect Yemen income tax expense which is paid through oil allocations with MOM in the Republic of Yemen ($2003 - $2,755,067, $3.18/Boe; ($2002 - $986,862, $1.75/Boe.)*

Net operating income in Yemen increased 7% in 2003 primarily as a result of the following:

- Production volumes increased 54%
- Oil prices increased 12%
- Royalty costs increased 395% as a result of three events:
  1. In 2002, TransGlobe had a cost oil reallocation between the Block 32 Joint Venture Group that decreased its royalty costs by $1,349,000.
  2. In 2003, TransGlobe had a final cost oil reallocation between the Block 32 Joint Venture Group that increased its royalty costs by $1,245,000.
  3. The Block 32 Joint Venture Group had recovered all of its historical cost pools by the second quarter of 2003, thereby reducing cost oil and increasing the production sharing oil which results in increased royalties and taxes to the Yemen government.
- Operating expenses increased 41% on a Boe basis as a result of an increase in the cost of the Transportation and Facilities Usage Contract with the MOM which allowed for a $0.40 increase in the export pipeline tariff following recovery of all historical costs. Increases in workover expenses on the wells and additional fluid handling expenses also contributed.

TransGlobe commenced production on Block 32 on November 3, 2000. Production from the block is shared between the Block 32 Joint Venture Group and MOM pursuant to a PSA. The PSA provides for MOM to receive a 3% royalty of gross production (10% over 25,000 Bopd) with the remaining 97% of revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of the revenue after deducting royalty. Cost recovery oil allows the Block 32 Joint Venture Group to recover operating costs and exploration and development expenditures as outlined in the PSA. The remaining oil is allocated to production sharing oil shared 65% by MOM and 33.25% by the Block 32 Joint Venture Group and 1.75% to YOC. The Block 32 Joint Venture Group's Yemen income taxes are paid out of the MOM's share of production sharing oil. These terms remain in place until gross proven recoverable reserves exceed 30 million barrels of oil or until gross production exceeds 25,000 Bopd.

The Block 32 Production Sharing agreement allows for the recovery of operating costs and capital costs from oil production. Operating costs are recovered in the quarter expended. The capital costs are amortized over two years with 50% recovered in the quarter expended and the remaining 50% recovered in the first quarter of the following calendar year. The Company will receive a larger share of production in the first quarter of each year as 50% of the previous year's historical costs are recovered. The amount

of oil required to recover capital and operating costs will vary depending upon the prevailing oil prices. The Company expects to receive after tax between 65% to 70% share of production in the first quarter of 2004 and then decrease to between 40% to 48% share of production in the balance of the year depending upon production volumes, oil prices, operating costs and eligible capital expenditures.

Canada

	2003		2002	
	$	$/Boe	$	$/Boe
Oil sales	344,630	27.00	210,827	22.01
Gas sales (6 : 1)	2,292,870	31.44	901,138	16.60
NGL sales	236,093	23.42	68,177	16.84
Other sales	106,154	-	-	-
	2,979,747	31.10	1,180,142	17.38
Royalties	442,925	4.62	164,748	2.43
Operating expense	694,476	7.25	448,894	6.61
Net operating income	1,842,346	19.23	566,500	8.34

Net operating income in Canada increased 225% in 2003 primarily as a result of the following:

- Production volumes increased 41% as a direct result of the 2003 drilling program.
- Gas prices increased 89% to average $5.24 per Mcf in 2003 compared to $2.77 per Mcf in 2002 while oil and natural gas liquids prices increased 23% and 39%, respectively.
- Royalty costs increased 90% on a Boe basis as a result of higher commodity prices and an increase in royalties on freehold lands which are not Alberta royalty tax credit eligible.
- Operating expenses increased 10% ($0.64) on a Boe basis mainly as a result of the strengthening of the Canadian dollar which increased the operating costs in Canada by $0.78 per Boe through currency conversion.

GENERAL AND ADMINISTRATIVE EXPENSES

	2003		2002	
	$	$/Boe	$	$/Boe
G&A (gross)	1,568,401	1.63	1,234,921	1.95
Capitalized G&A	(278,257)	(0.29)	(392,403)	(0.62)
Overhead recoveries	(83,807)	(0.09)	(21,827)	(0.03)
G&A (net)	1,206,337	1.25	820,691	1.30

General and administrative expenses increased 47% and decreased 4% on a Boe basis as a result of the following:

- Increases were experienced in personnel costs with additional employees and consultants, office overhead costs, insurance costs and public company administration costs.
- The strengthening of the Canadian dollar against the United States dollar increased G&A costs by $0.12 per Boe through currency conversion.

DEPLETION AND DEPRECIATION EXPENSE

	2003		2002	
	$	$/Boe	$	$/Boe
Republic of Yemen	5,516,000	6.37	3,960,000	7.02
Canada	737,000	7.69	317,000	4.67
	6,253,000	6.50	4,277,000	6.77

In Yemen unproven properties in the amount of $11,683,986 were excluded from costs subject to depletion and depreciation. This represents a portion of the costs incurred in Block S-1. These costs will be included in the depletable base as Block S-1 is developed or as impairment is determined.

In Yemen, depletion and depreciation on a Boe basis decreased 9% to $6.37 per Boe in 2003 from $7.02 in 2002 primarily as a result of the following:

- Increase in the Yemen Proved reserves resulted in a lower depletion rate.

In Canada, depletion and depreciation on a Boe basis increased 65% to $7.69 per Boe in 2003 from $4.67 in 2002 primarily as a result of the following:

- Increase in the depletion rate occurred with the increase in production volumes.
- The strengthening of the Canadian dollar against the United States dollar increased the Canadian depletion and depreciation by $0.55 per Boe through currency conversion.

INCOME TAXES

	2003	2002
Future income tax	$ (2,448,085)	$ (67,168)
Current income tax	2,755,067	986,862
	$ 306,982	$ 919,694

The future income tax recovery of $2,448,085 is a result of recognizing a portion of the future tax benefits in Canada. The recording of these future tax benefits in Canada is a direct result of the successful Canadian drilling program carried out in 2003. The Company has unrecognized future tax benefits in Canada in the amount of $1,641,643 which may be recognized in the future with continued drilling successes in Canada.

Current income tax expense in 2003 of $2,755,067 (2002 - $986,862) represents income taxes incurred and paid under the laws of the Republic of Yemen pursuant to the PSA on Block 32. The increase is a result of increased oil prices and increased production volumes of which the Yemen government's share has increased due to recovery of all historical costs. The Yemen government's share of production sharing oil includes royalties and income taxes.

CAPITAL EXPENDITURES/DISPOSITIONS

Capital Expenditures

	2003	2002
Republic of Yemen	$ 9,012,022	$ 5,435,398
Canada	5,217,084	1,041,146
	14,229,106	6,476,544
Proceeds on sale of property and equipment	(442,103)	(133,587)
Net capital expenditures	$ 13,787,003	$ 6,342,957

Capital expenditures in Yemen in 2003 are primarily comprised of the following:

Block 32 ($4,347,955)

- Drilling, completion and tie ins of four wells at Tasour and drilling of one exploration well.
- High pressure water injection expenditures and production equipment.
- Final contingent payments on an additional working interest acquired in 2000, which consisted of $800,000 in 2003 (2002 - $160,000) (six $160,000 payments, one for each cumulative million barrels of gross oil production between 7 million barrels to a maximum of 12 million barrels). All obligations of this purchase were finalized in 2003.

Block S-1 ($4,633,929)

- Drilling and associated production testing of two wells at An Nagyah, completion of one well at An Naeem and costs associated with commercial development of An Nagyah.

Capital expenditures in Canada in 2003 are primarily comprised of the following:

Canada ($5,217,084)

- Costs related to drilling, completing or recompleting and associated equipping and tie in costs for a nine well exploration and development program.
- Oil and gas lease acquisitions associated with the 2003 and 2004 exploration and development program.

Dispositions ($442,103)

- Proceeds on disposal of oil and gas properties represent dispositions in Canada of minor assets of $78,962 and disposition of seismic data in the United States of $363,141. A gain on disposition of the seismic data in the United States was recorded in other income as there is no associated cost base in this cost centre.

FINDING AND DEVELOPMENT COSTS

	2003		2002	
	Proved	Proved + Probable	Proved	Proved + Probable
Total capital expenditure	$ 14,229,107	$ 14,229,107	$ 6,476,544	$ 6,476,544
Net change from previous year's future capital	2,158,637	11,303,354	634,524	465,967
	$ 16,387,744	$ 25,532,461	$ 7,111,068	$ 6,942,511
Reserve additions and revisions (MBoe)	2,360.7	4,872.5	1,209.7	1,390.2
Average cost per Boe	$ 6.94	$ 5.24	$ 5.88	$ 4.99
Three year average cost per Boe	$ 6.40	$ 5.47	$ 6.75	$ 6.36

The finding and development costs shown above have been calculated in accordance with Canadian National Instrument 51-101, Standards of Disclosure for Oil and Gas Activities introduced in 2003 and the 2002 numbers have been restated to reflect the new Standards.

The aggregate of the exploration and development costs incurred in the most recent financial year and the change during that year in estimated future development costs generally will not reflect total finding and development costs related to reserves additions for that year.

RECYCLE RATIO

	Three Year Average	2003	2002	2001
Netback ($/Boe)	$ 11.89	$ 9.72	$ 15.36	$ 11.69
Proved finding and development costs ($/Boe)	$ 6.40	$ 6.94	$ 5.88	$ 5.73
Recycle ratio	1.86	1.40	2.61	2.04

The decrease in the 2003 recycle ratio to 1.40 compared to 2002 of 2.61 mainly relates to a lower netback in Yemen in 2003 which is a result of historical cost pool allocations between partners and achieving full historical cost pool recovery during Q2 2003. The recycle ratio measures the efficiency of TransGlobe's capital program by comparing the cost of finding and developing proved reserves with the netback from production. The ratio is calculated by dividing the netback by the proved finding and development cost on a Boe basis. Netback is defined as net sales less operating, general and administrative, foreign exchange (gain) loss, interest and current income tax expense per Boe of production.

OUTSTANDING SHARE DATA

Common Shares issued and outstanding, as at April 1, 2004 are 54,091,439.

LIQUIDITY AND CAPITAL RESOURCES

Funding for the Company's capital expenditures in 2003 was provided by cash flow from operations and working capital.

At December 31, 2003 the Company had working capital of $2,537,369, zero debt and a revolving credit facility of Cdn$2,500,000 and an acquisition/development credit facility of Cdn$2,000,000. The Company expects to expand its available credit facilities during the second quarter of 2004.

The Company expects to fund its 2004 exploration and development program (budgeted at $20,000,000 firm and contingent) through the use of working capital, cash flow, debt and equity financing as required. The use of our credit facilities during 2004 is expected to remain within conservative guidelines of less than a debt to cash flow ratio of 1 : 1. The Company raised $2,053,005 (net after costs) on a flow through financing in December 2003 to partially fund the Canadian exploration program. This amount is included in the

working capital at December 31, 2003. Should cash flow be negatively impacted by reduction in production volumes or commodity prices, the Company has some flexibility in decreasing its Canadian capital budget in excess of its flow through share commitments.

In December 2002, the Company announced the approval of a Normal Course Issuer Bid to acquire up to 4,855,435 common shares over a 12 month period expiring December 8, 2003. As a result of the significant increase in share price in 2003, the Company only acquired 100,000 common shares at a price of Cdn$0.60/share in 2003. The acquired shares have been returned to treasury and cancelled. The Normal Course Issue Bid terminated December 8, 2003.

COMMITMENTS AND CONTINGENCIES

As part of its normal business, the Company entered into arrangements and incurred obligations that will impact the Company's future operations and liquidity. The principal commitments of the Company are as follows:

	2004	2005	2006	2007
Office and equipment leases	$ 142,000	$ 142,000	$ 143,000	$ 48,000

Also, the Company entered into a contract to sell 1,500 gigajoules (GJ) per day (approximately 1500 Mcfpd) of natural gas in Canada from April 1 to October 31, 2004 for Cdn$5.795/GJ.

CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with generally accepted accounting principles requires that management make appropriate decisions with respect to the selection of accounting policies and in formulating estimates and assumptions that affect the reported amount of assets, liabilities, revenues and expenses. The following is included in MD&A to aid the reader in assessing the critical accounting policies and practices of the Company. The information will also aid in assessing the likelihood of materially different results being reported depending on management's assumptions and changes in prevailing conditions which affect the application of these policies and practices. Significant accounting policies are disclosed in Note 1 of the consolidated financial statements.

Oil and Gas Reserves Determination

The process of estimating reserves is complex. It requires significant judgements and decisions based on available geological, geophysical, engineering and economic data. These estimates may change substantially as additional data from ongoing development and production activities becomes available and as economic conditions impact oil and gas prices and costs. All of the Company's properties are evaluated by independent petroleum engineering consultants.

Full Cost Accounting for Oil and Gas Activities

Depletion and Depreciation Expense

The Company uses the full cost method of accounting for exploration and development activities. In accordance with this method of accounting, all costs associated with exploration and development are capitalized whether successful or not. The aggregate of net capitalized costs, estimated future development costs less estimated salvage values and estimated future site restoration costs is amortized using the unit of production method based on estimated proved oil and gas reserves.

An increase in estimated proved oil and gas reserves will result in a corresponding reduction in depletion and depreciation expense. A decrease in estimated future development costs will result in a corresponding reduction in depletion and depreciation expense.

Unproven Properties

Certain costs related to unproved properties and major development projects are excluded from costs subject to depletion and depreciation until the earliest of a portion of the property becomes capable of production, development activity ceases or impairment occurs. These properties are reviewed quarterly and any impairment is transferred to the costs being depleted or, if the properties are located in a cost centre where there is no reserve base, the impairment is charged directly to earnings.

Ceiling Test

The full cost method of accounting requires the calculation of a ceiling test which limits the net capital costs carried to an amount that is equal to the estimated future net revenues from the Company's oil and gas properties plus the cost (net of impairment) of unproved properties. The test is a cost recovery test and is not intended to represent an estimate of fair market value. The test is performed quarterly. If the net carrying cost of the oil and gas properties exceeds the indicated limit then the difference is charged to earnings.

Income Tax Accounting

The Company has recorded a future income tax asset in 2003. This future income tax asset is an estimate of the expected benefit that will be realized by the use of deductible temporary differences in excess of carrying value of the Company's Canadian property and equipment against future estimated taxable income. These estimates may change substantially as additional information from future production and other economic conditions such as oil and gas prices and costs become available.

NEW ACCOUNTING STANDARDS

Asset Retirement Obligations

Effective January 1, 2004 the Company will change its accounting policy with respect to accounting for asset retirement obligations. CICA section 3110, essentially the same as FASB's Statement No. 143, "Accounting for Asset Retirement Obligations" ("FAS 143"), requires an entity to record the fair value of a liability for an asset retirement obligation in the period in which it is incurred. When initially recorded, the liability is added to the related property, plant and equipment, subsequently increasing depletion and depreciation expense. In addition, the liability is accreted for the change in present value in each period. Upon adoption of CICA section 3110, the Company will adjust its existing provision for site restoration and abandonment liability retroactively with restatement of prior years financial statements.

The Company has estimated that the cumulative effect will be to recognize an asset retirement liability of $467,399, eliminate the provision for site restoration and abandonment liability of $153,209, increase property and equipment by $386,353 and increase deficit by $72,163.

Stock-Based Compensation Plans

Effective January 1, 2004, CICA section 3870, "Stock-based Compensation and Other Stock-based Payments", will require all public companies to expense all stock-based compensation. This standard provides for the retroactive adoption of fair value accounting effective January 1, 2004 which results in an increase in deficit and contributed surplus of $283,000. After January 1, 2004 the fair value of stock-based compensation will be recognized as an expense in the financial statements.

The Company uses stock-based compensation as a significant part of the Company's overall compensation package to its directors, officers and employees and therefore the Company expects this Standard may materially impact earnings with no effect on cash flows from operations. Based on stock option grants in prior years that will affect 2004 and stock option grants to date in 2004, it is expected that the effect on 2004 earnings will be approximately $1.1 million with no effect on cash flow from operations. The full effect on this Standard cannot be determined accurately at this time, as it will depend on future events such as number of options granted, volatility of the Company's stock price and other relevant factors.

Oil and Gas Full Cost Accounting

In July 2003 the AcSB issued Accounting Guideline 16, "Oil and Gas Accounting - Full Cost" ("AcG-16"), replacing AcG-5 which is effective January 1, 2004, AcG-16 provides for methodology consistent with CICA section 3063, "Impairment of Long-lived Assets", CICA section 3475, "Disposal of Long-lived Assets and Discontinued Operations" and FASB Statement No. 144, "Accounting for the Impairment and Disposal of Long-lived Assets".

The new standards prescribe the recognition of impairment only if the carrying amount of a long-lived asset is not recoverable from its undiscounted cash flows and measure the impairment amount as the difference between the carrying amount and the fair value. In addition, discontinued operations disclosure will be required upon the disposition of a cost centre of the entity rather than an entire business segment.

This Guideline is not expected to have a material effect on the Company.

Accounting for Derivative Instruments and Hedging Activities

Effective January 1, 2004 the Company will adopt CICA Accounting Guideline 13, "Hedging Relationships" ("AcG-13"). AcG-13 has essentially the same criteria to be satisfied before the application of hedge accounting is permitted as the corresponding requirements of the Financial Accounting Standards Board ("FASB") Statement No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("FAS 133").

This accounting standard requires that every derivative instrument, including certain derivative instruments embedded in other contracts, be recorded on the balance sheet as either an asset or liability measured at fair value. These standards further establish that changes in the fair value be recognized currently in earnings unless the arrangement can meet the "effective hedge" criteria.

The Guideline is not expected to have a material effect on the Company.

RISKS

The Company is exposed to a variety of business risks and uncertainties in the international petroleum industry including commodity prices, exploration success, production risk, foreign exchange, interest rates, government regulation, changes of laws affecting foreign ownership, political risk of operating in foreign jurisdictions, taxes, environmental preservation and safety concerns.

Many of these risks are not within the control of management, but the Company has adopted several strategies to reduce and minimize the effects of these factors:

- The Company applies rigorous geological, geophysical and engineering analysis to each prospect.
- The Company utilizes its in-house expertise for all international ventures and employs and contracts professionals to handle each aspect of the Company's business.
- The Company maintains U.S. dollar bank accounts which is its main operating currency.
- The Company maintains a conservative approach to debt financing and currently has no long-term debt.
- The Company maintains insurance according to customary industry practice, but cannot fully insure against all risks.
- The Company conducts its operations to ensure compliance with government regulations and guidelines.
- The Company retains independent petroleum engineering consultants to determine year-end Company reserves and estimated future net revenues.
- The Company manages commodity prices by entering physical fixed price sales contracts when deemed appropriate.

QUARTERLY FINANCIAL SUMMARY

	2003			
	Q-4	Q-3	Q-2	Q-1
Oil and gas sales, net of royalties	$ 4,488,447	$ 4,158,664	$ 4,139,106	$ 4,375,493
Cash flow from operations	$ 1,894,490	$ 2,192,540	$ 2,368,713	$ 2,891,258
Cash flow from operations per share				
- Basic	$ 0.04	$ 0.04	$ 0.05	$ 0.06
- Diluted	$ 0.04	$ 0.04	$ 0.05	$ 0.06
Net income	$ 3,413,717	$ 290,540	$ 775,713	$ 1,425,258
Net income per share				
- Basic	$ 0.06	$ 0.01	$ 0.01	$ 0.03
- Diluted	$ 0.06	$ 0.01	$ 0.01	$ 0.03

	2002			
	Q-4	Q-3	Q-2	Q-1
Oil and gas sales, net of royalties	$ 5,459,364	$ 2,964,411	$ 2,859,258	$ 1,971,072
Cash flow from operations	$ 4,380,792	$ 2,111,302	$ 1,951,125	$ 1,266,633
Cash flow from operations per share				
- Basic	$ 0.09	$ 0.04	$ 0.04	$ 0.02
-Diluted	$ 0.09	$ 0.04	$ 0.04	$ 0.02
Net income	$ 3,197,791	$ 1,040,470	$ 873,125	$ 315,003
Net income per share				
- Basic	$ 0.07	$ 0.02	$ 0.02	$ 0.01
- Diluted	$ 0.06	$ 0.02	$ 0.02	$ 0.01

Cash flow from operations is a non-GAAP measure that represents cash generated from operating activities before changes in non-cash working capital. We consider this a key measure as it demonstrates our ability to generate the cash flow necessary to fund future growth through capital investment. Cash flow from operations may not be comparable to similar measures used by other companies.

Significant variations between quarters are as follows:

- Q4, 2003 increase in net income to $3,413,717 is mainly a result of recognizing future tax benefits in Canada of $2,448,085 and recording a gain on disposal of seismic data in the United States of $363,141.

- Q4, 2002 increases in oil and gas sales, net of royalties, cash flow from operations and net income were impacted by historical cost oil reallocation of $1,496,000 between partners on Block 32 in Yemen which resulted in lower royalties in that quarter.

Management's Report

The consolidated financial statements of TransGlobe Energy Corporation were prepared by management within acceptable limits of materiality and are in accordance with Canadian generally accepted accounting principles. Management is responsible for ensuring that the financial and operating information presented in this annual report is consistent with that shown in the consolidated financial statements.

The consolidated financial statements have been prepared by management in accordance with the accounting policies as described in the notes to the consolidated financial statements. Timely release of financial information sometimes necessitates the use of estimates when transactions affecting the current accounting period cannot be finalized until future periods. When necessary, such estimates are based on informed judgements made by management.

Management has designed and maintains an appropriate system of internal controls to provide reasonable assurance that all assets are safeguarded and financial records properly maintained to facilitate the preparation of consolidated financial statements for reporting purposes.

Deloitte & Touche LLP, an independent firm of Chartered Accountants appointed by the shareholders, have conducted an examination of the corporate and accounting records in order to express their opinion on the consolidated financial statements. The Audit Committee, consisting of three independent directors, has met with representatives of Deloitte & Touche LLP and management in order to determine if management has fulfilled its responsibilities in the preparation of the consolidated financial statements. The Board of Directors has approved the consolidated financial statements.

Ross G. Clarkson
President &
Chief Executive Officer

David C. Ferguson
Vice President, Finance &
Chief Financial Officer

April 1, 2004

Independent Auditors' Report

To the Shareholders of
TransGlobe Energy Corporation:

We have audited the consolidated balance sheets of **TransGlobe Energy Corporation** as at December 31, 2003 and 2002 and the consolidated statements of income and deficit and cash flows for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada and the United States of America. These standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of TransGlobe Energy Corporation as at December 31, 2003 and 2002 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles. As required by the Company Act (British Columbia), we report that, in our opinion, these principles have been applied on a consistent basis.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta, Canada
February 27, 2004

COMMENTS BY AUDITORS FOR U.S. READERS ON CANADA-U.S. REPORTING DIFFERENCES

In the United States of America, reporting standards for auditors require the addition of an explanatory paragraph (following the opinion paragraph) outlining changes in accounting policies that have been implemented in the financial statements. As discussed in Note 1 to the consolidated financial statements, in 2002 the Company changed its method of accounting for stock-based compensation to conform to the Canadian Institute of Chartered Accountants Handbook recommendations, Section 3870.

Deloitte & Touche LLP

Chartered Accountants

Calgary, Alberta, Canada
February 27, 2004

Consolidated Statements of Income and Deficit

(Expressed in U.S. Dollars)

	Year Ended December 31, 2003	Year Ended December 31, 2002
REVENUE		
Oil and gas sales, net of royalties	$ 17,161,710	$ 13,254,105
Other income	374,239	42,108
	17,535,949	13,296,213
EXPENSES		
Operating	3,706,096	1,843,273
General and administrative	1,206,337	820,691
Foreign exchange (gain) loss	157,133	(6,988)
Interest	1,173	16,154
Depletion and depreciation	6,253,000	4,277,000
	11,323,739	6,950,130
Income before income taxes	6,212,210	6,346,083
Income taxes (Note 6)		
- future	(2,448,085)	(67,168)
- current	2,755,067	986,862
	306,982	919,694
NET INCOME	5,905,228	5,426,389
Deficit, beginning of year	(12,298,309)	(17,724,698)
Deficit, end of year	$ (6,393,081)	$ (12,298,309)
Net income per share (Note 8)		
Basic	$ 0.11	$ 0.11
Diluted	$ 0.11	$ 0.10

Consolidated Balance Sheets

(Expressed in U.S. Dollars)

	December 31, 2003	December 31, 2002
ASSETS		
Current		
Cash and cash equivalents	$ 4,451,751	$ 2,595,170
Accounts receivable	2,383,459	2,984,000
Prepaid expenses	161,011	88,837
	6,996,221	5,668,007
Property and equipment		
Canada (Note 2)	8,083,428	3,651,305
Republic of Yemen (Note 3)	18,562,857	15,066,835
	26,646,285	18,718,140
Future income tax asset (Note 6)	1,572,310	-
	$ 35,214,816	$ 24,386,147
LIABILITIES		
Current		
Accounts payable and accrued liabilities	$ 4,458,852	$ 919,074
Provision for site restoration and abandonment	153,209	122,209
	4,612,061	1,041,283
Commitments and Contingencies (Note 10)		
SHAREHOLDERS' EQUITY		
Share capital (Note 5)	36,995,836	35,643,173
Deficit	(6,393,081)	(12,298,309)
	30,602,755	23,344,864
	$ 35,214,816	$ 24,386,147

APPROVED BY THE BOARD

Ross G. Clarkson, Director

Lloyd W. Herrick, Director

Consolidated Statements of Cash Flows

(Expressed in U.S. Dollars)

	Year Ended December 31, 2003	Year Ended December 31, 2002
CASH FLOWS RELATED TO THE FOLLOWING ACTIVITIES:		
OPERATING		
Net income	$ 5,905,228	$ 5,426,389
Adjustments for:		
Depletion and depreciation	6,253,000	4,277,000
Gain on sale of property and equipment	(363,142)	-
Performance bonus expense paid in shares (Note 5)	-	73,631
Future income taxes	(2,448,085)	(67,168)
Cash flow from operations	9,347,001	9,709,852
Changes in non-cash working capital (Note 7)	3,117,398	(2,478,700)
	12,464,399	7,231,152
FINANCING		
Issue of share capital (Note 5)	2,269,705	(308)
Repurchase of share capital	(41,267)	-
	2,228,438	(308)
INVESTING		
Purchase of property and equipment		
Yemen	(9,012,022)	(5,435,398)
Canada	(5,217,084)	(1,041,146)
Proceeds on disposal of property and equipment	442,103	133,587
Changes in non-cash working capital (Note 7)	950,747	532,437
	(12,836,256)	(5,810,520)
NET INCREASE IN CASH AND CASH EQUIVALENTS	1,856,581	1,420,324
CASH AND CASH EQUIVALENTS, BEGINNING OF YEAR	2,595,170	1,174,846
CASH AND CASH EQUIVALENTS, END OF YEAR	$ 4,451,751	$ 2,595,170

Notes To The Consolidated Financial Statements

Years Ended December 31, 2003 and December 31, 2002
(Expressed in U.S. Dollars, unless otherwise stated)

1. SIGNIFICANT ACCOUNTING POLICIES

Basis of consolidation

These consolidated financial statements include the accounts of the Company and its wholly-owned subsidiaries, TransGlobe Oil and Gas Corporation, TransGlobe Petroleum International Inc. and TG Holdings Yemen Inc.

Accounting principles

These consolidated financial statements are prepared in accordance with accounting principles generally accepted in Canada, which conform in all material respects with accounting principles generally accepted in the United States of America, except as disclosed in Note 14.

Property and equipment

The Company follows the full cost method of accounting for oil and gas operations whereby all costs associated with the exploration for and development of oil and gas reserves are capitalized on a country-by-country basis. Such costs include land acquisition costs, geological and geophysical expenses, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

The capitalized costs, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on the estimated gross proven reserves and determined by independent petroleum engineers. Oil and gas reserves and production were converted into equivalent units of 6,000 cubic feet of natural gas to one barrel of oil.

Costs of acquiring and evaluating unproved properties and major development projects are initially excluded from the depletion and depreciation calculation. These costs are assessed periodically to ascertain whether impairment has occurred.

The capitalized costs less accumulated depletion and depreciation, future income taxes and the provision for future site restoration costs in each cost centre are limited to an amount equal to the estimated future net revenue from proven reserves plus the cost (net of impairment) of unproven properties.

The total capitalized costs less accumulated depletion and depreciation, future income taxes and the provision for future site restoration costs of all cost centres is further limited to an amount equal to the estimated future net revenue from proven reserves plus the cost (net of impairment) of unproven properties of all costs centres less estimated future site restoration costs, general and administrative expenses, financing costs and income taxes.

Proceeds from the sale of oil and gas properties are applied against capitalized costs, with no gain or loss recognized, unless such a sale would alter the rate of depletion and depreciation by more than 20 percent, in which case a gain or loss on disposal is recorded.

Substantially all of the Company's exploration, development and production activities are conducted jointly with others and accordingly, these consolidated financial statements reflect only the Company's proportionate interest in such activities.

Estimated future site restoration costs are provided for using the unit-of-production method and remaining proven reserves. Costs are estimated by the Company based on current regulations, costs, technology and industry standards. The annual charge is included in the provision for depletion and depreciation. Actual site restoration expenditures are charged to the accumulated provision account as incurred.

Furniture and fixtures are depreciated at declining balance rates of 20 to 30 percent.

Foreign currency

The Company uses the United States dollar as its reporting currency since the majority of the Company's business is transacted in United States dollars. The Company and its subsidiaries are considered to be integrated operations and the accounts are translated using the temporal method. Under this method, monetary assets and liabilities are translated at the rates of exchange in effect at the balance sheet date; non-monetary assets at historical rates and revenue and expense items at the average rates for the period, other than depletion and depreciation which are translated at the same rates of exchange as the related asset. The net effect of the foreign currency translation is included in current operations.

Cash and cash equivalents

Cash includes actual cash held and short-term investments such as treasury bills with original maturity of less than three months.

Revenue recognition

The Company records oil and gas revenue at the time of physical transfer to purchaser.

Income taxes

The Company records income taxes using the liability method. Under this method, future income tax assets and liabilities are measured using the enacted tax rates expected to apply to taxable income in the years in which the temporary differences are expected to be recovered or settled.

Flow through shares

The Company has financed a portion of its exploration and development activities in Canada through the issue of flow through shares. Under the terms of these share issues, the tax attributes of the related expenditures are renounced to subscribers. To recognize the foregone tax benefits, share capital is reduced and a future income tax liability is recorded by the income tax amount related to the renounced deductions.

Stock options

The Company has a stock option plan as described in Note 5. No compensation expense has been recorded upon the granting of the options at market prices. Effective January 1, 2002, the Company adopted CICA 3870 "Stock Based Compensation and Other Stock Based Payments". As permitted by CICA 3870, the Company has applied this change prospectively for new awards granted on or after January 1, 2002. For 2003 and 2002 the Company has calculated the impact on net earnings and earnings per share on a proforma basis (Note 5(h)). For periods prior to January 1, 2002 the Company did not recognize any compensation expense when stock options were issued to employees.

Per share amounts

Net income per share is calculated using the weighted average number of shares outstanding during the year. Diluted net income per share is calculated using the treasury stock method. The treasury stock method assumes that the proceeds received from the exercise of "in-the-money" stock options are used to repurchase common shares at the average market price.

Measurement uncertainty

The amounts recorded for depletion and depreciation of property and equipment, the provision for site restoration costs and the ceiling test calculation are based on estimates of proved reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the effect on the consolidated financial statements of changes in such estimates in future periods could be significant.

2. PROPERTY AND EQUIPMENT - CANADA

		2003		2002
Oil and gas properties	$	9,707,851	$	4,618,485
Furniture and fixtures		250,296		201,539
Accumulated depletion and depreciation		(1,874,719)		(1,168,719)
	$	8,083,428	$	3,651,305

During the year the Company capitalized overhead costs relating to exploration and development activities of $206,153 (2002 - $153,569).

Depletion and depreciation expense includes $31,000 (2002 - $16,000) related to the provision for site restoration which is calculated based on a total future estimated cost of $551,104 (2002 - $319,000).

3. PROPERTY AND EQUIPMENT - REPUBLIC OF YEMEN

		2003		2002
Oil and gas properties				
- Block 32	$	17,953,690	$	13,575,336
- Block S-1		12,650,485		8,016,556
- Other		81,682		81,943
Accumulated depletion and depreciation		(12,123,000)		(6,607,000)
	$	18,562,857	$	15,066,835

The Company commenced production on Block 32 in November 2000. This represented the early stages of a major development program contracted under the Production Sharing Agreement ("PSA") which continues to 2020, with provision for a five year extension. In October 2003, the Yemen Ministry of Oil and Minerals approved the Development Plan and Development Area for the Block S-1 PSA which will have a 20 year term with provision for a five year extension. Unproven properties in the amount of $11,683,986 were excluded from costs subject to depletion and depreciation representing a portion of the costs incurred in Block S-1. During the year the Company capitalized overhead costs relating to exploration and development activities of $239,717 (2002 - $238,834).

Block 32 (13.81087% working interest)

The PSA provides for the Ministry of Oil and Mineral Resources ("MOM") in the Republic of Yemen to receive a royalty of 3% (10% over 25,000 barrels of oil per day ("Bopd")) of gross production with the remaining 97% of revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 60% of 97% of the revenue limited to operating costs and allocated recoverable exploration and development expenditures as outlined in the PSA. Cost recovery oil is 100% for the account of the Block 32 Contractor (Joint Venture Partners) to recover operating costs and exploration and development expenditures. The remaining production sharing oil is shared 65% by MOM and 35% by the Block 32 Contractor which is further shared 5% Yemen Oil Company ("YOC")/95% Block 32 Contractor. These terms remain in place as long as proven recoverable reserves do not exceed 30 million barrels of oil (gross) or production of 25,000 Bopd.

Block S-1 (25% working interest)

The PSA provides MOM with a sliding scale royalty of 3%-10% based on daily oil production between 0-100,000 Bopd with the remaining revenue split between cost recovery oil and production sharing oil. Cost recovery oil is up to a maximum of 50% of after royalty revenue limited to operating costs and allocated recoverable exploration and development expenditures, as outlined in the PSA, to be utilized 100% by the Block S-1 Contractor. The balance of the revenue is allocated to production sharing oil and is shared 65%-80% by MOM and 35%-20% by the Block S-1 Contractor (which is further shared 17.5% YOC/82.5% Block S-1 Contractor) based on the production level.

4. LONG-TERM DEBT

The Company has a Cdn$2,500,000 revolving loan facility and a Cdn$2,000,000 non-revolving acquisition/development facility with a Canadian chartered bank. The loan facilities bear interest at the bank's Canadian prime rate plus three quarters of one percent and Canadian prime rate plus one percent, respectively, and are secured by a first floating charge debenture over all Canadian assets of the Company, a general assignment of book debts and certain negative pledges. At December 31, 2003 $nil (2002 - $nil) was drawn on these loan facilities.

5. SHARE CAPITAL

a) Authorized

The authorized share capital is 500,000,000 common shares with no par value.

b) Issued

	Number of shares	Amount
Balance, December 31, 2001	51,244,801	$ 35,637,019
Future tax effect (c)	-	(67,168)
Share issue costs	-	(309)
Performance bonus expense paid in shares (d)	250,000	73,631
Balance, December 31, 2002	51,494,801	35,643,173
Exercise of stock options (g)	985,000	216,700
Repurchase of share capital (e)	(100,000)	(41,267)
Private placement net of issue costs (f)	1,363,637	2,053,005
Future tax effect of flow through shares (f)	-	(875,775)
Balance, December 31, 2003	53,743,438	$ 36,995,836

c) In December 2001, the Company issued 519,000 flow through common shares in a private placement at Cdn$0.49 per share for net proceeds of US$155,797, subscribed by insiders of the Company. The terms of the flow through shares provide that the Company renounce Canadian tax deductions in the amount of Cdn$254,310 to the subscribers with the entire amount to be expended by the Company by December 31, 2002. As at December 31, 2002, the entire amount was spent. As described in Note 1, share capital is reduced and future income taxes are increased by the estimated amount of the future income taxes payable by the Company ($67,168) as a result of renouncing the expenditures to subscribers.

d) Pursuant to an employment contract and the Company meeting certain performance criteria, the Company issued 250,000 common shares to the President of the Company in 2002 recorded at market price at date of issue.

e) In March 2003, the Company repurchased 100,000 shares at Cdn$0.60 and cancelled the shares pursuant to a normal course issuer bid approved in December 2002. The normal course issuer bid terminated December 8, 2003.

f) In December 2003, the Company issued 1,363,637 flow through common shares in a private placement at Cdn$2.20 per share for net proceeds of US$2,053,005. Insiders of the Company subscribed for 65,000 shares. The terms of the flow through shares provide that the Company renounce Canadian tax deductions in the amount of Cdn$3,000,001 to the subscribers with the entire amount to be expended by the Company by December 31, 2004. As described in Note 1, share capital is reduced and future income taxes are increased by the estimated amount of the future income taxes payable by the Company ($875,775) as a result of renouncing the expenditures to subscribers.

g) Share purchase options

The Company adopted a new stock option plan in May 2003 (the "Plan"). The maximum number of common shares to be issued upon the exercise of options granted under the Plan is 7,103,580 common shares. All incentive stock options granted under the Plan will have a per-share exercise price not less than the trading market value of the common shares at the date of grant and will vest as to 50% of the options, six months after the grant date, and as to the remaining 50%, one year from the grant date.

	2003		2002	
	Number of Options	**Weighted-Average Exercise Price**	Number of Options	Weighted-Average Exercise Price
Options outstanding at beginning of year	3,624,500	$ 0.32	2,379,500	$ 0.31
Granted	120,000	0.47	1,400,000	0.32
Exercised	985,000	0.22	-	-
Expired	-	-	(155,000)	0.22
Options outstanding at end of year	2,759,500	$ 0.36	3,624,500	$ 0.32
Options exercisable at end of year	2,639,500	$ 0.36	2,924,500	$ 0.32

The following table summarizes information about the stock options outstanding at December 31, 2003:

	Options Outstanding			Options Exercisable		
Range of Exercise Prices	Number Outstanding at Dec. 31, 2003	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price	Number Exercisable at Dec. 31, 2003	Weighted-Average Remaining Contractual Life	Weighted-Average Exercise Price
$ 0.22	300,000	0.3	$ 0.22	300,000	0.3	$ 0.22
Cdn0.45	20,000	0.8	Cdn0.45	20,000	0.8	Cdn0.45
Cdn0.55	200,000	2.4	Cdn0.55	200,000	2.4	Cdn0.55
Cdn0.39	40,000	2.8	Cdn0.39	40,000	2.8	Cdn0.39
Cdn0.73	679,500	1.6	Cdn0.73	679,500	1.6	Cdn0.73
Cdn0.50	1,400,000	3.3	Cdn0.50	1,400,000	3.3	Cdn0.50
Cdn0.63	120,000	4.5	Cdn0.63	-	-	-
	2,759,500	2.5	$ 0.36	2,639,500	2.4	$ 0.36

h) Stock-based compensation

The Company accounts for its stock-based compensation plan using the intrinsic-value of the options granted whereby no costs have been recognized in the financial statements for stock options granted to employees and directors at market values. Effective January 1, 2002 under Canadian generally accepted accounting principles, the impact of using the fair value method on compensation costs and recorded net earnings must be disclosed. If the fair value method had been used, the Company's net earnings per share would approximate the following pro forma amounts (the pro forma amounts shown do not include the compensation costs associated with stock options granted prior to January 1, 2002):

		2003		2002
Compensation costs	$	143,000	$	140,000
Net income:				
As reported		5,905,228		5,426,389
Pro forma		5,762,228		5,286,389
Net income per share:				
As reported - Basic	$	0.11	$	0.11
- Diluted	$	0.11	$	0.10
Pro forma - Basic and diluted	$	0.11	$	0.10

The fair value of each option granted on the date of grant using the Black-Scholes option-pricing model with weighted average assumptions for grants is as follows:

	2003	2002
Risk free interest rate (%)	5.40	5.05
Expected lives (years)	2.50	5.00
Expected volatility (%)	97.01	66.35
Dividend per share	0.00	0.00

The weighted average fair market value of stock options granted in 2003 was $0.19 per option (2002 - $0.18 per option).

6. INCOME TAXES

The Company's future Canadian income tax assets are as follows:

		2003		2002
Temporary differences related to:				
Oil and gas properties	$	2,142,233	$	2,379,563
Non-capital losses carried forward		964,781		907,782
Share issue expenses		106,939		130,261
Valuation allowance		(1,641,643)		(3,417,606)
	$	1,572,310	$	-

The Company has deductible temporary differences of approximately Cdn$3,240,000 of non-capital losses carried forward and Cdn$7,552,000 of income tax pools in excess of the carrying value of the Company's Canadian property and equipment. The Company also has $12,700,000 of income tax losses in the United States of America. The Canadian losses carried forward expire between 2006 and 2011 and the United States of America losses carried forward expire between 2006 and 2020. In total, these temporary differences would generate a future income tax asset of Cdn$4,166,891 on Canadian operations. A valuation allowance of Cdn$2,128,391 has been recorded to reduce this amount to the amount which is considered to be more likely than not to be recovered.

Current income taxes in the amount of $2,755,067 (2002 - $986,862) represents income taxes incurred and paid under the laws of the Republic of Yemen.

The provision for income taxes has been computed as follows:

	2003	2002
Computed Canadian expected income tax expense at 40.62% (2002 - 42.15%)	$ 2,523,400	$ 2,674,874
Non-deductible Crown charges (net of ARTC)	95,773	64,036
Resource allowance	(61,471)	(2,773)
Different tax rates in the Republic of Yemen	327,559	(1,872,869)
Future income tax assets and recovery	(2,448,085)	(67,168)
Other differences	(130,194)	123,594
	$ 306,982	$ 919,694

7. SUPPLEMENTAL CASH FLOW INFORMATION

	2003	2002
Operating activities		
Decrease (increase) in current assets		
Accounts receivable	$ 1,335,741	$ (2,317,826)
Prepaid expenses	(72,174)	(28,150)
Increase (decrease) in current liabilities		
Accounts payable	1,853,831	(132,724)
	$ 3,117,398	$ (2,478,700)
Investing activities		
Decrease (increase) in current assets		
Accounts receivable	$ (735,200)	$ 309,598
Increase (decrease) in current liabilities		
Accounts payable	1,685,947	222,839
	$ 950,747	$ 532,437
Interest paid	$ 1,173	$ 16,154
Taxes paid	$ 2,755,067	$ 986,862

8. NET INCOME PER SHARE

	2003	2002
Basic		
Net income per share	$ 0.11	$ 0.11
Weighted average number of shares outstanding	52,070,638	51,449,596
Diluted		
Net income per share	$ 0.11	$ 0.10
Weighted average number of shares outstanding	53,779,217	51,944,926

9. SEGMENTED INFORMATION

In 2003 the Company operated in two geographic segments, the Republic of Yemen and Canada. The property and equipment in each geographic segment are disclosed in Notes 2 and 3.

The results of operations for the year ended December 31, 2003 are comprised of the following:

	Republic of Yemen	Canada	Total
REVENUE			
Oil and gas sales, net of royalties	$ 14,624,888	$ 2,536,822	$ 17,161,710
EXPENSES			
Operating	3,011,620	694,476	3,706,096
Depletion and depreciation	5,516,000	737,000	6,253,000
Segmented operations	$ 6,097,268	$ 1,105,346	7,202,614
Other income, includes a gain on sale of property and equipment in the United States of America of $363,142			374,239
			7,576,853
General and administrative			1,206,337
Foreign exchange (gain) loss			157,133
Interest			1,173
Income taxes (Note 6)			306,982
NET INCOME			$ 5,905,228

In the Republic of Yemen, the Company sells all of its production to one purchaser.

The results of operations for the year ended December 31, 2002 are comprised of the following:

	Republic of Yemen	Canada	Total
REVENUE			
Oil and gas sales, net of royalties	$ 12,238,711	$ 1,015,394	$ 13,254,105
EXPENSES			
Operating	1,394,379	448,894	1,843,273
Depletion and depreciation	3,960,000	317,000	4,277,000
Segmented operations	$ 6,884,332	$ 249,500	7,133,832
Other income			42,108
			7,175,940
General and administrative			820,691
Foreign exchange (gain) loss			(6,988)
Interest			16,154
Income taxes (Note 6)			919,694
NET INCOME			$ 5,426,389

In the Republic of Yemen, the Company sells all of its production to one purchaser.

10. COMMITMENTS AND CONTINGENCIES

The Company is committed to office and equipment leases over the next five years as follows:

2004	142,000
2005	142,000
2006	143,000
2007	48,000

11. FINANCIAL INSTRUMENTS

Carrying values of financial instruments, which include accounts receivable, accounts payable and accrued liabilities approximate their fair value due to the short-term or the floating interest rate nature of these amounts.

The Company has foreign exchange risk due to the fact that it operates internationally using foreign currencies. The Company has commodity price risk associated with its sale of crude oil and natural gas.

The majority of the accounts receivable are in respect of oil and gas operations. The Company generally extends unsecured credit to these customers and therefore the collection of accounts receivable may be affected by changes in economic or other conditions. Management believes the risk is mitigated by the size and reputation of the companies to which they extend credit. The Company has not experienced any material credit loss in the collection of accounts receivable to date.

12. COMPARATIVE FIGURES

Certain of the prior period's comparative figures have been reclassified to conform with the current period's presentation.

13. SUBSEQUENT EVENT

Subsequent to December 31, 2003, the Company entered into a contract to sell 1,500 gigajoules (GJ) per day of natural gas in Canada from April 1 to October 31, 2004 for Cdn$5.795/GJ.

14. DIFFERENCES BETWEEN GENERALLY ACCEPTED ACCOUNTING PRINCIPLES IN CANADA AND THE UNITED STATES OF AMERICA

The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles (Canadian GAAP or Cdn. GAAP) which differ in certain material respects from those principles that the Company would have followed had its consolidated financial statements been prepared in accordance with United States of America generally accepted accounting principles (U.S. GAAP).

Escrowed shares

For U.S. GAAP purposes, escrowed shares would be considered a separate compensatory arrangement between the Company and the holder of the shares. Accordingly, the fair market value of shares at the time the shares are released from escrow will be recognized as a charge to income in that year with a corresponding increase in share capital. The difference in share capital between Canadian GAAP and U.S. GAAP represents the effect of applying this provision in 1995 when 187,500 escrow shares were released resulting in an increase in share capital of $833,333 with the offset to deficit.

Stock-based compensation

The Company has a stock-based compensation plan as more fully described in Note 5. With regard to its stock option plan, the Company applies APB Opinion No. 25 as interpreted by FASB Interpretation No. 44 in accounting for this plan and accordingly no compensation cost has been recognized. Had compensation expense been determined based on fair value at the grant dates for the stock option grants consistent with the method under SFAS No. 123, the proforma effect on the Company's net income would be as follows:

			2003		2002
Compensation costs		$	143,000	$	140,000
Net income:					
As reported			5,905,228		5,426,389
Pro forma			5,762,228		5,286,389
Net income per share:					
As reported	- Basic	$	0.11	$	0.11
	- Diluted	$	0.11	$	0.10
Pro forma	- Basic and diluted	$	0.11	$	0.10

The foregoing information is calculated in accordance with the Black-Scholes option-pricing model, using the following data and assumptions:

	2003	2002
Risk free interest rate (%)	5.40	5.05
Expected lives (years)	2.50	5.00
Expected volatility (%)	97.01	66.35
Dividend per share	0.00	0.00

Flow through shares

The Company records the renouncement of tax deductions related to flow through shares by reducing the share capital and recording a future tax liability in the amount of the estimated cost of the tax deductions flowed to the shareholders. United States of America accounting principles require that the share capital on flow through shares be stated at the quoted market value of the shares at the date of issuance. In addition, the temporary difference that arises as a result of the renouncement of the deductions, less any proceeds received in excess of the quoted market value of the shares is recognized in the determination of income tax expense for the period. The effect of applying this provision to the Company's financial statements would result in an increase in income tax expense and future tax liability by $875,775 in 2003, $67,168 in 2002 and $335,020 in 2000 representing the tax effect of the flow through shares and a corresponding decrease to income tax expense and future tax liability by $875,775 in 2003, $67,168 in 2002 and $335,020 in 2000 to record the recognition of the benefit of tax losses available to the Company equal to the liability arising from renouncing tax pools to the subscribers.

Asset retirement obligations

In 2001, the FASB approved Statements of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations (SFAS 143) for US GAAP reporting purposes effective for fiscal years beginning after June 15, 2002. SFAS 143 requires recognition of a liability for the future retirement obligations associated with our property, plant and equipment, which includes oil and gas wells and facilities. These obligations, which generally relate to dismantlement and site restoration, are initially measured at fair value, which is the discounted future value of the liability. This fair value is capitalized as part of the cost of the related asset and amortized to expense over its useful life. The liability accretes until we expect to settle the retirement obligation.

Had this change in accounting policy been adopted the effect would be to recognize an asset retirement liability of $467,399, eliminate the provision for site restoration and abandonment liability of $153,209, increase property and equipment net of accumulated depletion and depreciation by $386,353, increase deficit by $72,163 and reduce net income by $81,046 (increase in depletion and depreciation expense of $32,384 and accretion expense of $48,662).

Consolidated balance sheets

Had the Company followed US GAAP, asset and liability sections of the balance sheet would have been reported as follows:

	2003		2002	
	Cdn. GAAP	U.S. GAAP	Cdn. GAAP	U.S. GAAP
Property and equipment - Canada	$ 8,083,428	$ 8,469,781	-	-
Asset retirement obligation	-	467,399	-	-
Provision for site restoration and abandonment	153,209	-	-	-

Had the Company followed U.S. GAAP, the shareholders' equity would have been reported as follows:

	2003		2002	
	Cdn. GAAP	U.S. GAAP	Cdn. GAAP	U.S. GAAP
Share capital	$ 36,995,836	$ 39,107,132	$ 35,643,173	$ 36,878,694
Deficit	(6,393,081)	(8,585,423)	(12,298,309)	(13,533,830)
	$ 30,602,755	$ 30,521,709	$ 23,344,864	$ 23,344,864

The reconciling items between share capital and deficit for Canadian and United States of America GAAP are $833,333 related to escrowed shares, $1,277,963 related to flow through shares and $81,046 related to depletion and depreciation expense and accretion expense affecting deficit only, as described above. There are no other balance sheet differences.

Consolidated statements of income

Had the Company followed U.S. GAAP, the statement of income would have been reported as follows:

	2003	2002
Net income for the year under Canadian GAAP	$ 5,905,228	$ 5,426,389
Adjustments, before income taxes:		
Depletion and depreciation expense	32,384	-
Accretion expense	48,662	-
Future income tax expense	875,775	67,168
Income taxes on the above items	-	-
Net income for the year under U.S. GAAP	$ 4,948,407	$ 5,359,221
Net income per share under U.S. GAAP - Basic	$ 0.10	$ 0.10
- Diluted	$ 0.09	$ 0.10

Cash flows

Under Canadian GAAP, reporting entities are permitted to present a sub-total prior to changes in non-cash working capital within operating activities. This information is perceived to be useful information for various users of the financial statements and is commonly presented by Canadian public companies. Under U.S. GAAP, this sub-total is not permitted to be shown and would be removed in the statements of cash flows for all periods presented.

Recent accounting pronouncements

The following standards issued by the FASB do not impact us:

- Interpretation No. 46, "Consolidation of Variable Interest Entities", effective for financial statements issued after January 31, 2003.
- SFAS No. 150, "Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity", effective for financial statements issued after June 15, 2003.
- SFAS No. 132 (revised 2003), "Employers' Disclosures about Pensions and Other Post Retirements Benefits - an amendment of SFAS No. 87, 88 and 106", effective for financial statements issued after December 15, 2003.
- SFAS No. 149, "Amendment of Statement 133 on Derivative Instruments and Hedging Activities", effective for contracts entered into or modified after June 30, 2003.

The Board of Directors

Back row, from left to right: Erwin Noyes, Fred Dyment, Geoffrey Chase, Lloyd Herrick
Front row, from left to right: Ross Clarkson, Robert Halpin

CORPORATE INFORMATION

OFFICERS AND DIRECTORS

Robert A. Halpin [1, 2, 3]
Director, Chairman of the Board

Ross G. Clarkson [3]
Director, President & CEO

Lloyd W. Herrick [2]
Director, Vice President & COO

Erwin L. Noyes [2, 3, 4]
Director

Geoffrey C. Chase [1, 2, 4]
Director

Fred J. Dyment [1, 3, 4]
Director

David C. Ferguson
Vice President, Finance, CFO & Secretary

1. Audit Committee
2. Reserves Committee
3. Compensation Committee
4. Governance and Nominating Committee

STOCK EXCHANGE LISTINGS

TSX:	TGL
AMEX:	TGA

TRANSFER AGENT AND REGISTRAR

Computershare Trust Company of Canada
Calgary, Toronto, Vancouver

LEGAL COUNSEL

Burnet, Duckworth & Palmer
Calgary, Alberta

BANKER

National Bank of Canada
Calgary, Alberta

AUDITOR

Deloitte & Touche LLP
Calgary, Alberta

EVALUATION ENGINEERS

Fekete Associates Inc.
Calgary, Alberta

Outtrim Szabo Associates Ltd.
Calgary, Alberta

EXECUTIVE OFFICES

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TransGlobe Energy Corporation Personnel

Back row, from left to right: James Bambrick (Manager, Geophysics), Edward Bell (Manager, International Exploration), David Ferguson (Vice President, Finance, CFO & Secretary), James Dowhaniuk (Manager, Domestic Exploration), Glenn Taylor (Manager, Domestic Operations)
Front row, from left to right: Harjeet Jugdev (Senior Accountant), Margaret Wardle (Executive Administrator and Office Manager)

ABBREVIATIONS

Cdn	Canadian
U.S.	United States
WTI	West Texas Intermediate
Bbl	barrel
Bopd	barrels of oil per day
MBbls	thousand barrels
MMBbls	million barrels
Mcf	thousand cubic feet
Mcfpd	thousand cubic feet per day
MMcf	million cubic feet
MMcfpd	million cubic feet per day
GJ	gigajoule
Tcf	trillion cubic feet
Boe	*barrel of oil equivalent
Boepd	*barrel of oil equivalent per day
MBoe	*thousand barrels of oil equivalent
NGL	natural gas liquids
$ MM	million dollars
the Company	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
TransGlobe	TransGlobe Energy Corporation and/or its wholly owned subsidiaries
AMEX	American Stock Exchange
CPF	Central Production Facility
PSA	Production Sharing Agreement
MOM	Ministry of Oil and Minerals, Republic of Yemen
YOC	Yemen Oil Company
MD&A	Management's Discussion and Analysis
GAAP	Generally Accepted Accounting Principles
G&A	General and Administrative
yr	year
Q	Quarter
○	drilling location
●	oil well
☼	gas well
⌖	abandoned well
⌀	injection well

* A Boe conversion ratio of 6 Mcf = 1 Bbl has been used. Boe's may be misleading, particularly if used in isolation. A Boe conversion ratio of 6 Mcf to 1 Bbl is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

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CORPORATION

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